BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NOS. 2022-254-E and 2022-281-E - ORDER NO. 2023-138

MARCH 8, 2023

IN RE:	Docket No. 2022-254-E – Application of Duke Energy Progress, LLC for Increase in Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for an Accounting Order and Docket No. 2022-281-E – Petition of Duke Energy Progress, LLC to Extend Accounting Order to Continue Regulatory Asset Treatment for Ongoing Grid Improvement Plan Cost	)	ORDER APPROVING COMPREHENSIVE SETTLEMENT AGREEMENT, ADJUSTING BASE RATES, AND CONTINUING GRID IMPROVEMENT PLAN COST DEFERRAL ACCOUNTING

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I. PROCEDURAL HISTORY

This matter comes before the Public Service Commission of South Carolina (the Commission or PSC) on the Application of Duke Energy Progress, LLC (DEP or the Company) filed September 1, 2022 (the Application) requesting authority to adjust and increase its electric rates, charges, and tariffs. The Application was filed pursuant to S.C. Code Ann. sections 58-27-820, 58-27-860, and 58-27-870 and S.C. Code Ann. Regs. 103-303 and 103-823.

On August 1, 2022, DEP submitted a letter as a Notice of Intent to File an Application. On August 2, 2022, the Commission Clerk's Office (Clerk's Office) issued a Notice of Proposed Schedule Dates Including Bill Insert to Customers. On that same date, DEP filed a letter requesting that the proposed schedule dates be held in abeyance. The Office of Regulatory Staff (ORS) filed a letter on August 3, 2022, concurring with DEP's request to hold the proposed schedule dates in abeyance. DEP then filed a letter on August 10, 2022, setting forth an agreement as to a proposed procedural schedule to which ORS filed a letter the same day indicating that there was no objection to this proposed schedule. On August 25, 2022, the South Carolina Department of Consumer Affairs (DCA) filed a Petition to Intervene in this docket, which was granted on September 15, 2022, by Order No. 2022-95-H. By letter dated August 25, 2022, DEP submitted the procedural schedule reached in the agreement between DEP, ORS, and DCA.

Consistent with the procedural schedule agreement, DEP filed an Application for Increase in Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and

Request for an Accounting Order on September 1, 2022. The Application included Exhibits A-D.

Contemporaneous with its Application, DEP filed the Direct Testimony of Michael P. Callahan, State President for DEP and Duke Energy Carolinas, LLC (DEC); Larry E. Hatcher, Senior Vice President of Customer Experience and Services for Duke Energy Corporation (Duke Energy); Jessica L. Bednarcik, Senior Vice President, Environmental, Health and Safety (EHS) and Coal Combustion Products (CCP) with Duke Energy Business Services, LLC (DEBS); Jonathan Byrd, Managing Director, Rate Design and Regulatory Solutions for DEBS; Rachel R. Elliott, Rates and Regulatory Strategy Manager with DEC, testifying on behalf of DEP; Steven M. Fetter, President, Regulation UnFettered; Retha Hunsicker, Vice President, Customer Experience Design and Solutions with DEBS; Brent C. Guyton, Director of Asset Management in Customer Delivery for DEC; Janice Hager, President of Janice Hager Consulting, LLC (Janice Hager); Daniel J. Maley, Director of Transmission Compliance Coordination with DEBS; Roger A. Morin, Emeritus Professor of Finance at the Robinson College of Business Georgia State University, Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, and principal with Utility Research International; Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer with DEBS; Tom Ray, Senior Vice President of Nuclear Operations for Duke Energy; Teresa Reed, Director of Rates and Regulatory Planning with DEBS; Sean P. Riley, partner and CPA with PricewaterhouseCoopers, LLP (PwC); Mark D. Rokoff, Business Development Manager with Burns and McDonnell Consultants, Inc. (Burns); John Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC (Gannett

Fleming); Nicholas G. Speros, Director of Accounting with DEBS; Jacob J. Stewart, Director, Health & Wellness with DEBS; Julie K. Turner, Vice President, Carolinas Coal Generation for Duke Energy; and Marcia E. Williams, Principal at Gnarus Advisors, LLC. Exhibits were included with the direct testimony of witnesses Guyton, Hager, Maley, Morin, Reed, Riley, Rokoff, Spanos, Speros, Stewart, and Williams. Hearing Exhibits No. 12-15, and 17-23. DEP filed Supplemental Direct Testimony and Exhibits for Witness Elliott on September 23, 2022 (Hearing Exhibit No. 10, pp. 245-398), and Second Supplemental Direct Testimony for Witness Elliott on November 21, 2022. The Company filed an Errata to the Direct Testimony and Exhibits of Witness Teresa Reed on September 23, 2022. Hearing Exhibit No. 17, pp. 1-2.

On September 6, 2022, the Commission issued Hearing Officer Directive Order No. 2022-91-H, which instructed the Company to provide the monthly impact of DEP's new proposed rates in dollars and percentages on average customers for years one and two separately for the residential, commercial, and industrial classes, as well as a note stating the usage per customer classification used to calculate the average monthly bill. The Company filed the requested information on September 8, 2022. On September 15, 2022, the Clerk's Office issued the Notice of Filing and Public Hearings and instructed the Company to publish it in newspapers of general circulation in the areas affected by the Company's Application one time by October 14, 2022 and provide Proof of Publication to the Commission on or before November 4, 2022. In addition, the Company was to furnish the Notice of Filing to customers by U.S. Mail via bill inserts or by electronic mail by November 10, 2022, and to provide proof of furnishing the Notice of Filing to the Clerk's Office by November 23, 2022. DEP complied with the instructions and submitted

Affidavits of Publication verifying the Notice was published in the *News & Press*, *The News*, *The Sumter Item*, *The Dillion Herald*, *The Link*, *The State*, *the Hartsville Messenger*, *Star Enterprise*, *Morning News* and *The Herald-Advocate*. In addition, DEP provided the affidavit of Ravenna Martinez on November 18, 2022, verifying that Notice of Filing and Public Hearings and Notice of Public Night Hearings had been furnished by U.S. mail to all applicable customers of Duke Energy Progress, LLC who receive their monthly bills via mail. The Notice of Filing and Public Hearings was furnished between the dates of October 2, 2022 to October 28, 2022 and the Notice of Public Night Hearings was furnished on November 4, 2022.

By letter dated September 21, 2022, AARP South Carolina (AARP) requested that the Commission hold three public in-person hearings in Florence, Bishopville, and Sumter, South Carolina. ORS filed a letter in support of this request on September 23, 2022. The Commission granted AARP's request via Directive Order No. 2022-657 which was issued on September 29, 2022.

On September 21, 2022, the Department of Defense and Federal Executive Agencies (DoD/FEA) filed a Petition to Intervene in this docket, which was granted on October 12, 2022, by Order No. 2022-106-H. On September 23, 2022, the South Carolina Small Business Chamber of Commerce filed a Petition to Intervene, which was also granted on October 12, 2022, by Order No. 2022-107-H.

On September 23, 2022, the Company filed Errata to the Application and to the Direct Testimony and Exhibits of Teresa Reed. Hearing Exhibit No. 17, pp. 1-244. The Company also filed Supplemental Direct Testimony and Exhibits of Rachel R. Elliott. Hearing Exhibit No. 17, pp. 245-476.

Petitions to Intervene were filed by Nucor Steel – South Carolina (Nucor) on October 4, 2022, by the South Carolina Coastal Conservation League (SCCCL), Southern Alliance for Clean Energy (SACE) and Vote Solar (Vote Solar) on October 7, 2022, and by the Sierra Club (Sierra Club) on October 27, 2022. On November 4, 2022, Walmart, Inc. (Walmart) filed a Petition to Intervene. On November 14, 2022, Nucor's Petition to Intervene was granted via Order No. 2022-119-H, SCCCL/SACE/Vote Solar's Petition was granted via Order No. 2022-120-H(A), and Sierra Club's Petition was granted via Order No. 2022-121-H. South Carolina Energy Users Committee (SCEUC) filed a Petition to Intervene with the Commission on November 14, 2022, which was granted via Order No. 2022-124-H. Finally, Walmart had its Petition to Intervene granted via Order No. 2022-126-H on December 1, 2022. No Party objected to the Petition to Intervene of any other Party.

The Clerk's Office issued Notice of Public Night Hearings on October 14, 2022, setting a public hearing in Bishopville, South Carolina on December 8, 2022, in Sumter, South Carolina on December 12, 2022, and in Florence, South Carolina on December 13, 2022.

The Company was represented in this proceeding by Camal O. Robinson, Esquire; Melissa Oellerich Butler, Esquire; Samuel J. Wellborn, Esquire; Frank R. Ellerbe, III, Esquire; Vordman Carlisle Traywick, III, Esquire; J. Ashley Cooper, Esquire; Thomas S. Mullikin, Esquire; Kiran H. Mehta, Esquire; and Brandon F. Marzo, Esquire. DCA was represented by Carri Grube Lybarker, Esquire, and Roger P. Hall, Esquire. The DoD/FEA was represented by Major Holly L. Buchanan, Esquire; Captain Marcus Duffy, Esquire; Emily W. Medlyn, Esquire; and Thomas A. Jernigan, Esquire. The South

Carolina Small Business Chamber of Commerce (SCSBCC) was represented by Charles L.A. Terreni, Esquire. Nucor Steel-South Carolina (Nucor Steel), was represented by Robert R. Smith, II, Esquire, and Michael K. Lavanga, Esquire. SACE, CCL, and Vote Solar, were represented by Kate Mixson, Esquire, and Emma C. Clancy, Esquire. The Sierra Club, was represented by Dorothy E. Jaffe, Esquire, and Justin T. Somelofske, Esquire. Walmart Inc. (Walmart), was represented by Stephanie U. Eaton, Esquire, and Carrie H. Grundmann, Esquire. The South Carolina Energy Users Committee (SCEUC), was represented by Scott Elliott, Esquire. The ORS is a party of record pursuant to Section 58-4-10(B) of the South Carolina Code of Laws and was represented by Benjamin P. Mustian, Esquire; Alexander W. Knowles, Esquire; Nicole M. Given, Esquire; Donna L. Rhaney, Esquire; and John C. "Chad" Torri, Esquire.

On December 1, 2022, the DCA filed the Direct Testimony and Exhibits of Eric Borden, Dr. David E. Dismukes, and Aaron L. Rothschild. Hearing Exhibit Nos. 28-31. The DoD/FEA filed the Direct Testimony and Exhibits of Brian C. Andrews, Michael P. Gorman, and Christopher C. Walters. Hearing Exhibit Nos. 32-36. The SCSBCC filed the Direct Testimony of James Anthony Ward. Nucor Steel filed the Direct Testimony and Exhibits of Billie S. LaConte and the Direct Testimony of Jeffry Pollock. Hearing Exhibit Nos. 39-41. An Errata to the Direct Testimony and Exhibits of Witness LaConte was filed on December 9, 2022 by Nucor. Hearing Exhibit No. 40, pp. 1-2. SACE, CCL, and Vote Solar filed the Direct Testimony and Exhibits of Dr. David G. Hill and Jim Grevatt. Hearing Exhibit Nos. 42-43, and 66. Walmart filed the Direct Testimony and Exhibits of Lisa V. Perry. Hearing Exhibit Nos. 44-45. SCEUC filed the Direct Testimony and Exhibits of Kevin W. O'Donnell. Hearing Exhibit Nos. 26-27.

On December 1, 2022, ORS filed the Direct Testimony and Exhibits of Richard A. Baudino, Brandon S. Bickley, Anthony D. Briseno, David J. Garrett, Donald Shane Hyatt, Elizabeth P. McGlone, Aaron K. Rabon, Courtney D. Radley, Anthony Sandonato, Michael L. Seaman-Huynh, Daniel F. Sullivan, Glenn A. Watkins, and Dan J. Wittliff, as well as the Direct Testimony of Dawn M. Hipp, Robert A. Lawyer, Daniel J. Roland, IV, and Omari R. Thompson. Hearing Exhibit Nos. 46-58, and 65. ORS filed the Corrected Direct Testimony of Witness Lawyer on December 2, 2022 as well as Exhibit AMS-2 to the Direct Testimony of Anthony Sandonato, which was inadvertently omitted from the original filing.

On December 15, 2022, DEP filed Rebuttal Testimony of Witnesses Bednarcik, Byrd, Callahan, James M. Coyne, Elliott, Fetter, Guyton, Hager, Morin, Newlin, Ray, Reed, Riley, Rokoff, Spanos, Kim H. Smith, Stewart, Turner, and Williams. Exhibits were included with the Rebuttal Testimony of Witnesses Bednarcik, Coyne, Elliott, Guyton, Morin, Newlin, Rokoff, Stewart, and Turner. DEP later filed the Supplemental Rebuttal Testimony of Witness Smith on December 22, 2022.

On December 22, 2022, DCA filed the Surrebuttal Testimony of Witnesses Borden, Dr. Dismukes, and Rothschild. The DoD/FEA filed the Surrebuttal Testimony of Witness Walters, along with the Surrebuttal Testimony and Exhibits of Witnesses Andrews and Gorman. Nucor Steel filed the Surrebuttal Testimony of Witnesses LaConte and Pollock. SACE, CCL, and Vote Solar filed the Surrebuttal Testimony of Witnesses Grevatt and Dr. Hill. Walmart filed the Surrebuttal Testimony and Exhibit of Witness Perry. SCEUC filed the Surrebuttal Testimony of Witness O'Donnell.

ORS also filed the Surrebuttal Testimony and Exhibits of Witnesses Baudino, Briseno, Seaman-Huynh, Sullivan, and Wittliff, as well as the Surrebuttal Testimony of Witnesses Bickley, Garrett, Hipp, McGlone, Rabon, Radley, Sandonato, Thompson, and Watkins on December 22, 2022.

Sierra Club did not prefile Direct or Surrebuttal Testimony of any witnesses in this proceeding.

ORS filed the Corrected Direct Testimony of Witnesses Hyatt, Rabon, and Watkins on January 6, 2023. ORS filed the Revised Surrebuttal Testimony of Witnesses Briseno, Hipp, Watkins and Seaman-Huynh on January 6, 2023. Nucor filed the Corrected Direct Testimony and Exhibit of Billie S. LaConte on January 12, 2023.

Several Parties filed briefs and motions in connection with this proceeding. These motions include 1) DEP's Motion to Strike Surrebuttal Testimony of the South Carolina Office of Regulatory Staff and Certain Intervenors; 2) DEP's Motion to Strike Surrebuttal Testimony of Dr. David G. Hill; 3) DEP's Motion in Limine to Exclude the Testimony of Dan J. Wittliff; and 4) ORS's Motion for Declaratory Ruling and Motion to Strike.

The Commission held public hearings for customers to speak on December 8, 2022, December 12, 2022, December 13, 2022, January 3, 2023, and January 5, 2023. Numerous customers of DEP attended these hearings and testified regarding the proposed increase in rates, affordability concerns, customer service issues, outages, issues related to vegetation management, and individual load usage.

On January 9, 2023, the Commission began the hearing for the Parties to present their witnesses in this docket. At the commencement of the proceeding, counsel for DEP informed the Commission that the Parties had reached a global, comprehensive settlement resolving all issues in the case, and requested a one-week recess in the proceeding to allow the Parties to memorialize the agreement and for certain Parties to file settlement testimony supporting the comprehensive settlement agreement. The Commission agreed to stay the proceeding related to DEP's Application until 9:30 a.m. on Tuesday, January 17, 2023.

The Company moved to withdraw Kim H. Smith's Supplemental Rebuttal Testimony on January 12, 2023. The Company indicated during the settlement agreement portion of the hearing on January 17, 2023, that, as a result of the comprehensive settlement reached in the docket, it would not move Witness Smith's Supplemental Rebuttal Testimony into the record.

On January 12, 2023, DEP filed a Comprehensive Settlement Agreement (Settlement Agreement) on behalf of the Parties resolving all issues in the docket. The Parties jointly moved for approval of the Settlement Agreement and certain Parties to the proceeding filed settlement testimony. The Commission resumed the hearing on January 17, 2023, and accepted the Settlement Agreement into evidence. The Commission also accepted into evidence the filed settlement testimony of the following witnesses for DEP: Callahan, Hatcher, Elliott, and Reed; for CCL, SACE, and Vote Solar, Grevatt; and for ORS, Hipp. Each of the witnesses who filed Settlement Testimony appeared before the Commission to testify and respond to questions. The filed non-settlement testimony and exhibits of the witnesses that had not filed settlement testimony were stipulated into the record by agreement between all Parties and with the consent of the Commission.

During the course of the hearing, DEP advised that the Parties agreed it was appropriate to consolidate Docket No. 2022-281-E, which is a separate docket evaluating

DEP's request for the continuation of its grid improvement plan deferral, with Docket No. 2022-254-E so as to resolve the issues addressed in Docket No. 2022-281-E in accordance with the proposed resolution as set forth in the Comprehensive Settlement Agreement. DEP then moved for the two dockets to be consolidated for hearing purposes in order to resolve both dockets, which was granted by Chair Florence P. Belser.

II. STATUTORY STANDARDS

The evidence supporting DEP's business and legal status is contained in its Application and testimony. DEP is a limited liability company duly organized and existing under the laws of the State of North Carolina engaged in the business of generating, transmitting, distributing, and providing electricity to public and private energy users for compensation. DEP is a public utility as defined under the laws of the State of South Carolina, and it is subject to the Commission's jurisdiction with respect to its rates, charges, tariffs, and terms and conditions of service as generally provided in S.C. Code Ann. sections 58-27-10 *et seq*. *See* Application ¶ 5.

The Company's current rates, excluding riders and the fuel cost component, were approved in Commission Order Nos. 2019-341 and 2019-454 in Docket No. 2018-318-E and affirmed by the Supreme Court of South Carolina in *Duke Energy Carolinas, LLC v. S.C. Off. of Regul. Staff*, 434 S.C. 392, 864 S.E.2d 873 (2021).

The Application, testimony of all Parties, exhibits, affidavits of publication, and public notices submitted by the Company comply with the procedural requirements of the South Carolina Code of Laws and the Regulations promulgated by the Commission.

South Carolina Code Ann. section 58-27-810 provides, "[e]very rate made, demanded or received by any electrical utility. . . . shall be just and reasonable." The

Commission must determine a fair rate of return that the utility should be allowed the opportunity to earn after recovery of the expenses of utility operations. The legal standards for this determination are set forth in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03 (1944) (*Hope*), and *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923) (*Bluefield*).

Bluefield holds that:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting the opportunities for investment, the money market and business conditions generally.

Bluefield, 262 U.S. at 692-93.

This Commission and the South Carolina courts have consistently applied the principles set forth in *Bluefield* and *Hope*. In *Southern Bell Tel. &Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 596 (1978) (*Southern Bell*), the South Carolina Supreme Court, quoting *Hope*, held: "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling . . . The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates, involves the balancing of investor and the consumer interests." *Id.*, 270 S.C. at 596-97, S.E.2d at 281 (*quoting* 320 U.S. at 602-03).

This Commission must exercise its responsibilities of permitting utilities an opportunity to earn a reasonable return on the property the utilities have devoted to serving the public, on the one hand, and protecting customers from rates that are so excessive as to be unjust or unreasonable, on the other, by "(a) Not depriving investors of the opportunity to earn reasonable returns on the funds devoted to such use as that would constitute a taking of private property without just compensation[, and] (b) Not permitting rates which are excessive." *Southern Bell*, 270 S.C. at 605, 244 S.E.2d at 286 (Ness, J. concurring and dissenting). Ultimately, this balancing of interests takes place within the context of a utility setting forth proposed rates - pursuant to Title 58, Chapter 27, Article 7 of the S.C. Code of Laws - for the purpose of the utility receiving revenue sufficient to yield a reasonable return.

The Commission's determination of a fair rate of return must be documented fully in its findings of fact and based exclusively on the evidence of record. *Porter v. S.C. Pub. Serv. Comm'n*, 332 S.C. 93, 98, 504 S.E.2d 320, 323 (1998).

The use of a test year is a well-established regulatory mechanism. The objective of using test year figures is to reflect typical operational conditions. The Company has the benefit of choosing its test year. Where an unusual situation indicates that the test year figures are atypical, the Commission should adjust the test year data. *Parker v. S.C.*

Pub. Serv. Comm'n, 280 S.C. 310, 312, 313 S.E.2d 290, 292 (1984). The Test Period for purposes of this Application is the 12-month period ending December 31, 2021, adjusted for actual costs through May 31, 2022, and projected costs from June 1, 2022, through August 31, 2022, for certain adjustments, including rate base, which were updated to actual costs in this proceeding.

The Commission's Findings of Fact and Conclusions of Law apply and reflect these standards.

III. FINDINGS OF FACT

Based upon the Application, the Settlement Agreement, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission makes the following findings of fact:

Jurisdiction

1. DEP is a limited liability company duly organized and existing under the laws of the State of North Carolina. It is a public utility under the laws of the State of South Carolina and is subject to the jurisdiction of this Commission pursuant to S.C. Code Ann. section 58-3-140(A). The Company is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in the northeastern portion of South Carolina, a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast and between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina and area in western North Carolina in and around the City of Asheville. DEP, with its offices and principal places of business in Raleigh, North Carolina, is a wholly-owned subsidiary of Duke Energy, with its offices and principal place of business in Charlotte, North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in South Carolina, including DEP, as generally provided in S.C. Code Ann. sections 58-27-10, *et seq*.

3. DEP is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to S.C. Code Ann. sections 58-27-820, 58-27-870, and S.C. Code Ann. Regs. 103-303 and 103-823.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base through August 31, 2022, subject to the terms of the Settlement Agreement.

Application

5. DEP, by its Application and initial Direct Testimony and Exhibits, originally sought a base increase of approximately $89,325,000 in its annual electric sales revenues from its South Carolina retail electric operations, including an ROE of 10.2% and a capital structure consisting of 47% debt and 53% equity.

6. DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base.

7. DEP, by its Rebuttal Testimony and Exhibits, revised its requested base revenue requirement to be approximately $88,506,000 million to incorporate the Company's adjustments filed in its Supplemental filing and the Company's Rebuttal position.

Settlement Agreement and Revenue Increase

8. On January 12, 2023, DEP filed the Settlement Agreement, along with its

Attachments A, B, C, D and E, on behalf of the Settling Parties agreeing to an ROE of 9.6% and a capital structure reflecting 47.57% debt and 52.43% equity. Settlement Agreement Attachment A reflects the Company's operating experience, accounting adjustments and an increase in annual revenues from base rates of approximately $52,297,000, exclusive of riders and mitigation measures contemplated in the Settlement Agreement, to be effective April 1, 2023. Settlement Agreement Attachment B shows, by customer class, the allocation of the increase in revenues and the respective rates of return by customer class.

9. The Commission, having carefully reviewed the Settlement Agreement and all of the evidence of record, finds and concludes that the provisions of the Settlement Agreement are just and reasonable as to all the Parties and are in the public interest. Therefore, the Settlement Agreement should be approved in its entirety. The specific terms of the Settlement Agreement are addressed in the following findings of fact and conclusions.

10. Based on the foregoing, the appropriate base revenue requirement increase is approximately $52,297,000, after accounting and pro forma adjustments, as set forth in Attachment A of the Settlement Agreement (Hearing Exhibit No. 6, pp. 35-49), as adjusted subject to the Settlement Agreement approved in this case.[1]

11. The Settlement Agreement provides that, unless specified otherwise, nothing in the Settlement Agreement binds Parties from taking an alternative position in

[1] The base revenue increase does not include the impact of the EDIT Rider reduction of ($16,426,000) as calculated in Attachment A of the Settlement Agreement. Hearing Exhibit 10, p. 3.

any current or future proceeding in South Carolina or any other jurisdiction. The Settlement Agreement also specifies that Settling Parties' agreement that the terms of the Settlement Agreement are reasonable as a whole does not in any way indicate any Party's position as to the reasonableness of any single term taken out of the context of the Settlement Agreement. The Commission finds and concludes that for the present case, the agreed-upon provision of the Settlement Agreement in Section B, Paragraph 5 is just and reasonable in light of the entirety of the evidence presented.

12. The complete Settlement Agreement with attachments is included herein as Order Exhibit No. 1 (Hearing Exhibit No. 6) and is incorporated by reference.

Return on Common Equity and Capital Structure

13. The ROE that the Company should be allowed an opportunity to earn is 9.60%, as set forth in Section B, Paragraph 7 of the Settlement Agreement. Hearing Exhibit No. 6, pp. 7-8.

14. As set forth in Section B, Paragraph 7 of the Settlement Agreement, the Parties agreed on a capital structure consisting of 52.43% common equity and 47.57% long-term debt. *Id.*

15. The Company's cost of debt is 3.77%, as set forth in Section B, Paragraph 7 of the Settlement Agreement. *Id.*

16. The Company's overall rate of return on rate base[2] (ROR) is 6.83%, as set forth in Section B, Paragraph 7 of the Settlement Agreement. *Id.*

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[2] Rate of return on rate base used herein refers to the rate of return on South Carolina retail rate base.

17. The capital structure, cost of debt, ROE, and ROR set by this Order will result in just and reasonable rates.

Excess Deferred Income Tax Mitigation

18. The Company proposed to continue the annual excess deferred income tax (EDIT) Rider updates for the following three categories of benefits: (1) Federal EDIT – Protected; (2) Federal EDIT – Unprotected, Property Plant & Equipment (PP&E)-related; and (3) Federal EDIT – Unprotected, non-PP&E-related. Additionally, the Company proposed to accelerate the flow back of the remaining portion of Federal unprotected EDIT related to PP&E over 2.17 years (26 months) beginning April 1, 2023, thereby reducing the number of years of amortization for Federal unprotected EDIT associated with PP&E from 20 years to 6.6 years.

19. Pursuant to the Settlement Agreement, the Company agreed to accelerate the return of deferred income tax benefits due through Unprotected EDIT associated with PP&E. The effect of this accelerated return begins with service rendered on April 1, 2023, and is expected to conclude in the period ending December 31, 2025 when the total balance of the Unprotected EDIT associated with PP&E is fully depleted.

20. The Company's proposed EDIT Rider, as modified per the terms of the Settlement Agreement, is just and reasonable, and will result in rates that are just and reasonable and should therefore be implemented. The appropriate annual revenue requirement for the EDIT Rider is an annual decrement of approximately $16,426,000.

Coal Ash Basin Closure Expense Adjustments (Coal Ash Regulatory Asset)

21. Since its last rate case, in Docket No. 2018-318-E, DEP has incurred additional costs in connection with the closure of the coal combustion residual (CCR),

also referred to as coal ash, surface impoundments at its coal-fired plant sites in South Carolina and North Carolina.

22. In this case, DEP sought recovery of approximately $106,836,000[3] of CCR closure costs (CCR Costs) on a South Carolina retail basis incurred through August 31, 2022.

23. Pursuant to the Settlement Agreement, the Company agrees to a permanent, one-time disallowance of $50,000,000 on a South Carolina retail basis of CCR Costs incurred through August 2022. In addition to this one-time disallowance, the Company will, per the Settlement Agreement, permanently forego recovery of any remaining coal ash costs sought by DEP but not allowed for recovery by the Commission in Docket No. 2018-318-E in all future cases.

24. The Settlement Agreement provides that, subject to Section B Paragraphs 11 and 12 (Hearing Exhibit No. 6, p. 9), the Settling Parties agree to the Company's continuation of deferred accounting treatment for CCR Costs, which will include a debt return only, at the most recent Commission approved debt rate for the deferral period and rate base treatment during the amortization period. The Settling Parties agree that the deferral will be subject to a review for reasonableness and prudency in the next general rate proceeding.

The Settlement Agreement provides that, other than the permanent disallowance of costs identified in Section B Paragraphs 11 and 12 (Hearing Exhibit No. 6, p. 9), the disallowance of CCR Costs is solely related to the Settlement Agreement and shall have

[3] Amount updated in DEP's supplemental filing. Hearing Exhibit 10.

no precedential effect on the recoverability of CCR Costs or the continuation of deferral accounting treatment in future proceedings, and the Settling Parties reserve their rights on any other legal issues or to advance any other positions on coal ash in future cases.

25. The Settlement Agreement requires the Settling Parties to engage in good faith negotiations prior to January 1, 2030, to resolve all issues and claims in connection with CCR Costs incurred by the Company after February 28, 2030, which shall not have any precedential effect and shall not impact or limit, in any way, a Settling Party's ability to advance in future proceedings any legal arguments, theories, positions, etc. regarding CCR Costs. Per the Settlement Agreement, this provision does not place any obligation upon any Party to resolve those issues and claims in a future proceeding, and each Party maintains complete discretion to approve or reject any proposed settlement for those issues and claims in a future proceeding. The Settling Parties agree that settlement on those issues will not be used as a rationale for future arguments on contested issues brought before the Commission.

26. The Commission finds and concludes that for the present case, the agreed-upon coal ash basin closure expense adjustments outlined in Section B Paragraphs 11 through 15 of the Settlement Agreement (Hearing Exhibit No. 6, pp. 9-10), are just and reasonable in light of all the evidence presented and that the result is in the public interest.

Expense Adjustments

27. The Settlement Agreement provides for certain expense adjustments that the Settling Parties have agreed upon; the revenue requirement effects of the agreed-upon issues are set out in detail in Settlement Agreement Attachment A (Hearing Exhibit No.

6, pp. 35-53). The Settling Parties agree that settlement on those issues will not be used as a rationale for future arguments on contested issues brought before the Commission. The Commission finds and concludes that for the present case the agreed-upon expense adjustments outlined in Settlement Agreement Attachment A (Hearing Exhibit No. 6, pp. 35-53) are just and reasonable in light of all the evidence presented and that the result is in the public interest.

Cost of Service Study and Rate Design

28. The rate design outlined in Attachment B through Attachment E of the Settlement Agreement results in just and reasonable rates. (Hearing Exhibit No. 6, pp. 54-67).

29. As set forth in the Settlement Agreement, the Company shall apply a 50% rate migration adjustment to residential and medium general service rate classes.

30. Pursuant to the Settlement Agreement, the Company shall allocate the increase in revenue across rate classes in a manner consistent with the cost of service study included in the Direct Testimony of Company Witness Hager, with proforma adjustments to reflect the Settlement Agreement, which results in the following revenue increase to each rate class:

Rate Class	**Allocation Percentage Including Riders**	**Allocation Percentage Excluding Riders**
RES	12.03%	12.71%
SGS	8.27%	8.83%
SGSTCLR	10.59%	11.53%
MGS	5.69%	6.06%
LGS	3.89%	3.87%
SI	6.40%	6.83%
TSS	18.44%	19.62%
ALS, SLS	14.96%	14.70%
SFL	6.80%	6.75%
SC-RETAIL	8.47%	8.83%

The allocation percentages to each rate class, inclusive of EDIT, are as follows:

Rate Class	**Allocation Percentage Including Riders**	**Allocation Percentage Excluding Riders**
RES	8.72%	9.20%
SGS	5.33%	5.69%
SGSTCLR	7.30%	7.95%
MGS	3.60%	3.84%
LGS	2.22%	2.21%
SI	3.86%	4.13%
TSS	14.05%	14.95%
ALS, SLS	10.19%	10.01%
SFL	3.51%	3.48%
SC-RETAIL	5.81%	6.06%

31. Pursuant to the Settlement Agreement, the Company shall reduce Rate Schedule LGS-TOU's on-peak energy charges by the reduction in the revenue requirement, exclusive of any EDIT decrements, allocated to Rate Schedule LGS-TOU.

32. Pursuant to the Settlement Agreement, the Company shall allocate the proposed reduction in the EDIT Rider to Rate Schedule LGS-TOU's on-peak, off-peak,

and discount energy periods.

33. The Settling Parties agree that neither the cost of service study adopted solely for purposes of this Settlement Agreement nor the revenue allocation agreed to by the Parties for purposes of this Settlement Agreement shall have any precedential effect in future proceedings, and all Parties may argue for different cost allocation, rate design, and revenue spread methodologies in future cases.

34. The Commission finds and concludes that, for the present case, the agreed-upon provisions outlined in Section B Paragraph 38 to the Settlement Agreement (Hearing Exhibit No. 6, pp. 17-18) are just and reasonable in light of all of the evidence presented and that the result is in the public interest.

Lead/Lag Study

35. The Settlement Agreement provides that the Company will perform a Lead-lag Study before its next general rate proceeding and present the results to the Commission and ORS. The Commission finds and concludes that, for the present case, the agreed-upon provision outlined in Section B Paragraph 39 to the Settlement Agreement (Hearing Exhibit No. 6, p. 18) is just and reasonable in light of all of the evidence presented.

Vegetation Management

36. The Settlement Agreement provides for certain provisions related to Vegetation Management that the Settling Parties have agreed upon. The Settling Parties agree that these provisions establish certain protections for customers within the Company's service area, to include (a) a quarterly report submitted by the Company to the Commission and ORS on the miles of transmission and distribution right-of-way that are

cut, sprayed, and maintained as part of the tree trimming and vegetation management work plan; (b) an annual action plan to be submitted by the Company on December 31st of each year for the succeeding 12-month period for all planned transmission and distribution miles of right-of-way to be maintained, and (c) restrictions on the utilization of vegetation management funds for vegetation management and tree trimming purposes only. The Commission finds and concludes that for the present case, the agreed-upon expense adjustments outlined in Section B Paragraph 40 of the Settlement Agreement (Hearing Exhibit No. 6, pp. 18-19), as well as the protective provisions described above, are just and reasonable in light of all the evidence presented and that the result is in the public interest.

Grid Improvement Plan and Distribution Planning

37. The Settlement Agreement provides for the Company to build upon the existing Integrated System & Operations Planning (ISOP) stakeholder process to inform and contribute to future Grid Improvement Plans (GIP) and requires the Company, biannually, to submit informational reports to the Commission on the status of the ISOP process, including a summary of stakeholder recommendations, through December 31, 2024. The distribution planning focus in the ISOP stakeholder process will include sharing data concerning distribution Non-Traditional Solutions (NTS), opportunities for stakeholders to provide inputs and recommendations on the Company's distribution NTS planning framework and analyses, and an opportunity to review and provide feedback on the results. Each iteration of the distribution NTS screening process will include identification of candidates for the development of distribution NTS. Per the Settlement Agreement, the Settling Parties have not taken a position on the underlying merits of this

commitment, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the commitments described in Section B Paragraph 41. Hearing Exhibit No. 6, pp. 19-20. The Commission finds and concludes that for the present case, the agreed-upon provisions outlined in Section B Paragraph 41 of the Settlement Agreement are just and reasonable in light of all the evidence presented. *Id*

38. The Settlement Agreement provides that the Company, subsequent to the release of its Climate Risk & Resilience Study Final Report, will work collaboratively with stakeholders to include members of the community, to discuss and work in good faith to develop and implement at least one potential target initiative as part of its GIP, to be informed by the Final Report, subject to approval by the Commission and included in an informational filing described in Section B Paragraph 41 of the Settlement Agreement. *Id.* As part of this provision, the Company shall evaluate the effectiveness of any implementation plans developed for the initiatives for potential use in expanded initiatives and budgeting in future GIPs, placing emphasis on those initiatives designed to address equity or environmental justice issues while also demonstrating the use of distributed energy resources as NTS. Per the Settlement Agreement, the Settling Parties have not taken a position on the underlying merits of this commitment, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the commitments described in Section B Paragraph 42. Hearing Exhibit No. 6, p. 20. The Commission finds and concludes that for the present case, the agreed-upon provisions outlined in Section B Paragraph 42 of the Settlement Agreement are just and reasonable in light of the entirety of the evidence presented. *Id.*

Energy Efficiency Opportunities

39. The Settlement Agreement provides that the Company will work with the Energy Efficiency Demand-Side Management (EE/DSM) Collaborative to develop and file its Income-Qualified (IQ) High-Energy Use pilot program and Tariffed On-Bill pilot program as soon as practicable, but no later than December 31, 2023, for Commission approval. Additionally, the Company agrees to file for approval to ramp up its proposed annual investments for all IQ program costs incurred by the Company in South Carolina to at least $1,000,000 by 2025, $750,000 of which will go toward the enhanced Neighborhood Energy Saver (NES) program, provided evaluation shows this to be feasible and subject to Commission approval. The Company also agreed as part of the Settlement Agreement to work with the EE/DSM Collaborative to develop a plan to increase its installation of comprehensive energy savings measures associated with the enhanced NES program in South Carolina, such as air sealing, insulation, and duct sealing. The Company further agrees to submit an informational update to the Commission with revised annual energy savings projections at the higher spending level and to work with the EE/DSM Collaborative to identify and address potential barriers to successfully deploying the additional spending. Per the Settlement Agreement, the Settling Parties have not taken a position on the underlying merits of this commitment, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the commitments described in Section B Paragraphs 43 through 45. Hearing Exhibit No. 6, pp. 20-21. The Commission finds and concludes that for the present case, the agreed-upon provisions of the Settlement Agreement in Section B Paragraphs 43-45 (Hearing Exhibit No. 6, pp. 20-21) are just and reasonable in light of the

entirety of the evidence presented.

Federal Inflation Reduction Act Action Plan

40. The Settlement Agreement provides that the Company will work with the EE/DSM Collaborative to develop a plan for integrated customer participation in the Inflation Reduction Act (IRA) for customers who participate in its IQ programs to maximize and expand benefits to highly electric energy burdened households. The Settlement Agreement provides that the Company will endeavor to have a final plan ready to be filed concurrently with the announced availability of IRA rebates in South Carolina. In addition, the Company will develop and implement an action plan to support all of its customers participation in the opportunities created by the IRA (e.g., helping customers understand which measures qualify for IRA rebates and tax credits). Pursuant to the Settlement Agreement, the Company will endeavor to have a final action plan ready to be filed concurrently with the announced availability of IRA rebates in South Carolina and offer to preview the final action plan with ORS. Per the Settlement Agreement, the Settling Parties have not taken a position on the underlying merits of this commitment, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the programs or initiatives described in Section B Paragraphs 46 through 47. Hearing Exhibit No. 6, p. 21 (Settlement Agreement). The Commission finds and concludes that for the present case, the agreed-upon provision of the Settlement Agreement in Section B Paragraphs 46-47 (Hearing Exhibit No. 6, p. 21) are just and reasonable in light of the entirety of the evidence presented.

Electric Energy Burden

41. The Settlement Agreement provides that the Company will address the

impact of an increase in rates on overall electric energy burden in its next general rate proceeding. The Commission finds and concludes that for the present case the agreed-upon provision of the Settlement Agreement in Section B Paragraph 49 is just and reasonable in light of the entirety of the evidence presented. *Id.*

Pending Motions

42. The Settlement Agreement provides that the Parties agree to hold in abeyance all pending motions, including an abeyance of any deadlines to file responses and/or replies. The Commission finds and concludes that for the presented case, the agreed-upon provision of the Settlement Agreement in Section B Paragraph 50 represents a fair and reasonable compromise of significantly contested issues and is approved by the Commission. *Id.* The Settlement Agreement, as a practical matter, rendered moot the motions made by the Parties and thus, need not be addressed dispositively.

IV. EVIDENCE AND CONCLUSIONS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

(Jurisdiction)

The evidence supporting these findings and conclusions is contained in the verified Application of the Company, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

DEP is an electric utility subject to the jurisdiction of the Commission pursuant to S.C. Code Ann. section 58-3-140(A) (Supp. 2010). The test year is the period of time selected to evaluate the cost of providing service and the adequacy of existing rates. Essential to this method of evaluating rates is the establishment of a cut-off date to ensure some degree of finality in the rate making process. *Parker v. S.C. Pub. Serv. Comm'n*, 280

S.C. 310, 312, 313 S.E. 2d 290, 291-92 (1984). South Carolina uses a historic twelve-month test period. 26 S.C. Code Ann. Regs. 103-823(A)(3). The historic test year approach uses the most recent 12-month period for which data is available at the time of filing a rate proceeding. A historic test year is based primarily upon the recorded results for the 12-month period, although the Commission can recognize adjustments to these results that are designed to shape the recorded year into a "normal" representation of the period. The Commission finds the 12 months ending December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base, to be the reasonable period upon which to base its ratemaking determination. The use of the test year, as applied in this case, is not contested by any Party.

These findings of fact are informational, procedural, and jurisdictional in nature and are not contested by any Party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

(Application)

The evidence supporting these findings and conclusions is contained in the Company's verified Application, the Settlement Agreement, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Commission last approved the Company's general electric rates and tariffs in Order No. 2019-341 in Docket No. 2018-318-E, which allowed the Company a 9.5% ROE. The test period in that case was the 12 months ended December 31, 2017, adjusted for known and measurable changes.

On September 1, 2022, DEP filed its Application and initial Direct Testimony and Exhibits, seeking a net increase of approximately $89,325,000. The Company stated that, recognizing the additional strain and challenge brought on by the COVID-19 pandemic and recent economic environment, the Company proposed to mitigate the impact of its rate request through the following measures: (a) accelerating the return of deferred income tax benefits resulting from the Federal Tax Cuts and Jobs Act of 2017 (the Tax Act) through its EDIT Rider and (b) stepping in the rate request over a two-year period, where in Year 1 the Company would reverse $15,000,000 of its cost of removal reserve for South Carolina distribution plant.[4] After factoring in the proposed decrease resulting from the change to the EDIT Rider and the reduction in rates resulting from the proposed decrement rider, the Year 1 net increase in retail revenues proposed in the Company's Application was approximately $53,335,000 or 8.6%. As proposed in the Application, in Year 2, the decrement rider would expire resulting in an increase in retail revenues of approximately $15,000,000 or 2.5%, for a cumulative net increase in retail revenues of approximately $68,335,000 or 11.1% over the two-year period following the rates effective date.

On January 12, 2023, DEP, together with the Settling Parties, filed the Settlement Agreement. DEP, by its Settlement Testimony and Exhibits to the Settlement Agreement, revised its requested base revenue requirement to approximately $52,297,000, exclusive of riders and mitigation measures contemplated in the Settlement Agreement, to be effective April 1, 2023, to incorporate the Company's adjustments filed in its Settlement Testimony and Exhibits. Hearing Exhibit No. 6, (Settlement Agreement). The rates

[4] The Company proposed to implement this $15,000,000 reduction through a decrement rider, which would expire at the end of Rate Year 1.

proposed in the Settlement Agreement generate an annual net revenue increase equaling approximately $35,871,000, or approximately 5.81%, inclusive of riders and mitigation measures contemplated in the Settlement Agreement, to be effective April 1, 2023.

DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a 12-month test period ending on December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base.

Need for Rate Increase

Company Witness Callahan testified that the Company's need for a rate increase is driven by investments to: (1) enhance DEP's service to customers and continue the Company's track record of operational excellence while keeping costs as low as possible; (2) improve the reliability and resiliency of DEP's grid in a manner to better customers' lives and the economy of this State; and (3) achieve a smarter, more efficient energy future for the benefit of customers. Tr. 645.4:1-14.

Regarding operations, Witness Callahan testified that DEP has made investments to ensure high-quality customer service, and made efforts to recruit, engage, and retain a talented diverse workforce. Tr.645.7:1-6. Witness Callahan testified that DEP has also invested in the deployment of smart meters and will continue to invest in modernizing the grid and offering customers operations and tools to better manage their energy usage and reduce their energy costs. Tr. 645.7:7-16. Additionally, he testified that DEP has deployed a new customer information system – Customer Connect – which has improved the way the Company interacts and provides information to customers. *Id.*

Witness Callahan also expounded on the Company's focus on increasing reliability and resiliency, explaining that DEP is investing in cleaner, highly-efficient generation resources, and that DEP plans to continue to invest in its distribution grid, smart meters, and tools to communicate with customers to continuously improve the customer experience and reliability. Tr. 645.8:1-645.9:9.

Witness Callahan testified that the Company is actively pursuing an orderly transition towards achieving a clean, secure energy future. Tr. 645.9:11. Accordingly, he explained that DEP has made investments in generation resources like solar, nuclear, and highly efficient natural gas plants, and emerging technologies like energy storage and vehicle electrification, as well as investments to comply with environmental regulations and support ash basin closure activities. Tr. 645.9:17-10.22.

Witness Callahan testified that the Company's most important objectives are to continue providing safe, reliable, affordable, resilient, and increasingly clean electricity to its customers with high quality customer service, both today and in the future. Tr. 645.17:13-645.18:4. He concluded that the Company's Application is made to support investments that benefit South Carolina and DEP's customers while preserving the Company's financing position while keeping prices for customers as low as possible. *Id.*

With respect to the costs sought by the Company, the Settlement Agreement is comprehensive and addresses all costs for which the Company is seeking recovery in this proceeding. The Commission finds that the costs reflected in the Settlement Agreement and the attachments thereto are just and reasonable and properly included in the revenue requirement.

<u>EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-12</u>

(Settlement Agreement and Revenue Increase)

The evidence supporting these findings and conclusions is contained in the verified Application of the Company, the Settlement Agreement, the testimony and exhibits of DEP Witnesses Callahan (Settlement), Elliott (Settlement), Reed (Settlement); ORS Witness Hipp (Settlement); and the entire record in this proceeding.

The Commission convened and conducted a hearing in this matter and has considered all issues raised by the Parties and evidence presented. Moreover, the Commission has carefully considered the terms of the Settlement Agreement and specifically the question of whether a rate increase embodying the terms contained in the Settlement Agreement would be just, fair, and reasonable; in the public interest; and would be in accordance with applicable law and sound regulatory policy. For the reasons set forth below, the Commission finds that the Settlement Agreement should be approved; will result in rates that are just and reasonable to all rate classes; is in the public interest; and will otherwise be in accordance with applicable law. The Settlement Agreement was accepted into the record of the hearing as Hearing Exhibit No. 6.

In its Application, the Company sought approval of an ROE of 10.2% and requested a revenue increase of approximately $89,325,000, or 14.5% after proforma adjustments, based on the adjusted data for the period of January 1, 2021, through December 31, 2021 (Test Year), adjusted for actual costs through May 31, 2022, and projected costs from June 1, 2022, through August 31, 2022, for certain adjustments. The Settlement provides for an ROE of 9.60% and a revenue increase of approximately $52,297,000 after proforma adjustments. However, DEP agrees to accelerate the return to customers of the Unprotected PP&E-related EDIT via the EDIT Rider beginning with all bills rendered on or after April 1, 2023, and concluding on or about December 31, 2025, when the total balance of the Unprotected PP&E-related EDIT, which will equal approximately $16,426,000 annually as of April 1, 2023 (grossed up for taxes), is projected to be depleted.

Using the EDIT Rider to accelerate the return of Unprotected PP&E-related EDIT to DEP's customers serves to reduce the overall impact on customers to a net annual increase of approximately $35,871,000, or approximately 5.81%. Under the Settlement Agreement a residential customer using 1,000 kWh per month would see a net monthly increase of $10.95, reflecting a $15.18 increase in base rates less a $4.23 reduction due to the EDIT Rider. Hearing Exhibit No. 6, pp. 7-9 (Settlement Agreement). According to the Settlement Agreement, the settlement rates will be effective beginning with bills rendered on and after April 1, 2023. *Id.*

The Settlement Agreement also adopts, except in limited and specified circumstances, "all recommendations, adjustments, and customer protections in the testimony and exhibits of ORS Witnesses." Hearing Exhibit No. 6, p. 7. In addition, DEP agrees to a permanent, one-time $50,000,000 disallowance on a South Carolina retail basis of coal ash basin closure costs (CCR Costs) incurred through August 2022 associated with ORS Witness Wittliff's recommended adjustments to the Company's CCR Costs, as well as agreeing to permanently forego recovery in any future cases of any remaining coal ash costs sought by DEP but not allowed for recovery by the Commission in Docket No. 2018-318-E. Hearing Exhibit No. 6, pp. 9-10 (Settlement Agreement).

The complete Settlement Agreement with attachments is attached as Order Exhibit No. 1 (Hearing Exhibit No. 6) and is incorporated by reference.

As a result of the Settlement Agreement and as agreed upon by the Parties therein, the Commission finds that all outstanding Motions filed by the Parties are moot.[5]

Commission Discussion

The Commission approves the Company's proposed revenue increase of approximately $52,297,000 annually, as set forth in Attachment A of the Settlement Agreement (Hearing Exhibit No. 6, pp. 35-53), adjusted per the terms of the Settlement Agreement approved herein.[6] Hearing Exhibit No. 6, pp. 7-9 (Settlement Agreement). The approved revenue increase is based on the following amounts of test year pro forma adjusted operating revenues, operating expenses, and original cost rate base (under present rates), which are to be used as the basis for setting rates in this proceeding: $621,745,000 of operating revenues, $535,067,000 of operating expenses, and $1,846,184,000 of original cost rate base, adjusted per the terms of the Settlement Agreement approved herein. *Id.*

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from this Order strike the appropriate balance between the interests of the Company's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of the Company in maintaining the Company's financial strength at a level that enables the

[5] These motions include 1) DEP's Motion to Strike Filed Surrebuttal Testimony of the South Carolina Office of Regulatory Staff and Certain Intervenors; 2) DEP's Motion to Strike Filed Surrebuttal Testimony of Dr. David G. Hill; 3) DEP's Motion in Limine to Exclude the Testimony of Dan J. Wittliff; and 4) ORS's Motion for Declaratory Ruling and Motion to Strike.
[6] The base revenue increase does not include the impact of the EDIT Rider reduction of ($16,426,000) as calculated in Attachment A of the Settlement Agreement. Hearing Exhibit 6.

Company to attract sufficient capital. As a result, the Commission concludes that the Settlement Agreement and the revenue requirement and the rates that will result from that revenue requirement established by this Order are just, reasonable, and in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-17

(Return on Common Equity and Capital Structure)

Cost of Capital

The evidence supporting these findings of fact is found in the verified Application; the Settlement Agreement; the testimony and exhibits of DEP Witnesses Newlin (Direct and Rebuttal), Morin (Direct and Rebuttal) and Coyne (Rebuttal); ORS Witnesses McGlone (Direct and Surrebuttal) and Baudino (Direct and Surrebuttal); DCA Witness Rothschild (Direct and Surrebuttal); DoD/FEA Witness Walters (Direct and Surrebuttal); and Walmart Witness Perry.

A. RATE OF RETURN ON COMMON EQUITY (ROE)

Summary of the Evidence

In its Application, the Company requested that its rates be set based upon an ROE of 10.2%, reflecting the ROE recommendation of DEP Witness Morin. Tr. 854.6:16. Witness Morin made his 10.2% ROE recommendation based upon a proxy group of 23 vertically integrated electric utilities. Tr. 854.33: 13-16. To arrive at his opinion, Witness Morin performed cost of equity studies including two variations of a Discounted Cash Flow (DCF) analysis, two variations of a Capital Asset Pricing Model (CAPM) analysis, and two risk premium methodologies. Tr. 854.7:1-16. These studies resulted in a variety of ROE estimates ranging from 9.3% to 11.1%, and his specific recommendation of

10.2% is at the midpoint of that range. *Id.*

In his Rebuttal Testimony, Witness Morin updated his ROE analyses using the same proxy group and econometric models and estimated that the Company's ROE had increased by 20 basis points, to 10.4%. Tr. 856.5:11-20. However, as indicated in the Rebuttal Testimony of Witness Newlin, DEP maintained its 10.2% ROE request to mitigate any further rate impacts to its South Carolina customers. Tr. 860.21:8-12. Witness Morin's Rebuttal Testimony further responded to intervenor Witness ROE recommendations as described below. Additionally, Witness Coyne's Rebuttal Testimony responded to the basis for ORS Witness Baudino's recommendation as derived from his analytical results.

ORS Witness Baudino's Direct Testimony recommended an ROE of 9.4%, the top of his recommended range of 9.13% to 9.4%, based upon a proxy group composed of 22 electric utilities. Tr. 1038.27:4-12. Witness Baudino performed analyses based upon two DCF methodologies and three variations of the CAPM. Tr. 1038.11:11-18. The model results ranged from 8.68% to 9.63% (DCF) and 8.38% to 16.60% (CAPM). Tr. 1038.18:11-13; Tr. 1038.26:20-21. Witness Baudino based his recommendation primarily on the results of his DCF analysis but noted that his recommendation is also within the range of results from his CAPM analysis. Tr. 1038.28:7-8. Witness Baudino also presented his views on DEP Witness Morin's ROE model results and recommendations. In his Surrebuttal Testimony, Witness Baudino responded to Witness Morin and Coyne's views regarding his Direct Testimony.

DCA Witness Rothschild's Direct Testimony recommended an ROE range of 8.48% to 9.39%, as well as a specific point within that range of 8.71%, based upon the same proxy group utilized by DEP Witness Morin. Tr. 902.9:13-902.11:11. Witness Rothschild employed the DCF model (two variations) and the CAPM (eight variations), the results of which indicated that DEP's ROE ranged from 8.48% to 9.39% (midpoint of 8.93%). *Id.* His ROE point recommendation of 8.71% approximates the midpoint of the lower end of that range and the midpoint of 8.93%. *Id.* Witness Rothschild also presented his views on DEP Witness Morin's ROE model results, and in his Surrebuttal Testimony, Witness Rothschild responded to Witness Morin's views regarding his Direct Testimony.

DoD/FEA Witness Walters's Direct Testimony recommended an ROE of 9.45%, based upon the same proxy group utilized by DEP Witness Morin. Tr. 914.4:17-20; Tr. 914.28:5. Witness Walters employed the DCF model (three variations), a CAPM analysis, and a risk premium model. Tr. 914.2323-914.24:2. As a result of his analysis, Witness Walters estimated that DEP's ROE ranged from 8.9% to 10.0%. Tr. 914.55:1-4. He selected a point recommendation of 9.45%, which is the midpoint of that range. *Id.* Witness Walters also presented his views on DEP Witness Morin's ROE model results and recommendations. In his Surrebuttal Testimony, Witness Walters responded to Witness Morin's views regarding his Direct Testimony.

Walmart Witness Perry's Direct Testimony analyzed S&P Global data regarding authorized ROEs from 2019 through November 2022. Her testimony indicates that the average ROE authorized during this period is 9.46%. Tr. 968.13:5-20. The average authorized ROE, considering only vertically integrated electric utilities, is 9.59%. *Id.*

The Settlement Agreement establishes the Parties' agreement that a 9.6% ROE is an acceptable compromise of the Parties' varying views on the appropriate ROE to be utilized in order to set just and reasonable rates in this case.

Commission Discussion

The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) (*Bluefield*), and *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish that ROE should be set at a level (i) commensurate with returns on investments in other firms having corresponding risks; (ii) sufficient to assure confidence in DEP's financial integrity; and (iii) sufficient to maintain DEP's creditworthiness and ability to attract capital on reasonable terms.

The Commission must balance the interests of the using and consuming public with that of the utility appearing before it. The Commission's determination of a fair rate of return must be based on reliable and probative evidence in the record. The Commission is bound by the parameters of evidence in the record, and hereby carefully evaluates the evidence submitted in this case as to the ROE the Company should be authorized the opportunity to earn.

In this case, after consideration of the evidence in the whole record, the Commission concludes that it is just and reasonable and a fair balancing of the interests of the Company and its customers to approve the ROE of 9.6% as set out in the Settlement Agreement. Hearing Exhibit No. 6, p. 7 (Settlement Agreement). An ROE of 9.6% is supported by the record evidence before the Commission, as it is within the ranges of ROE estimates recommended by Witnesses Morin and Walters, and only slightly higher than the ranges estimated by Witnesses Baudino and Rothschild.

As such, an ROE of 9.6% is a reasonable compromise in this proceeding, and the result is – in consideration of all factors – in the public interest.

B. CAPITAL STRUCTURE

Summary of the Evidence

In its Application, the Company requested that its rates be set based upon a capital structure of 53% equity and 47% long-term debt, as recommended by DEP Witness Newlin. Tr. 860.2:14-17. Witness Newlin indicated in his Direct Testimony that this capital structure was optimal for the Company and balanced the needs of DEP and its customers. *Id.*

In her Direct Testimony, ORS Witness McGlone recommended that the Company's capital structure be set at the level of 52.43% common equity and 47.57% long-term debt, which was DEP's actual capital structure as of August 31, 2022. Tr. 860.6:1-3. DoD/FEA Witness Walters and DCA Witness Rothschild approached the capital structure with reference to a comparison of capital structures of the 23 utility holding companies in Witness Morin's proxy group, although their ultimate recommendations differed – Witness Walters recommended a capital structure of 52% equity and 48% long-term debt, while Witness Rothschild recommended 43.12% equity and 56.88% long-term debt. Tr. 914.4:20-22; Tr. 902.8:13-14. DoD/FEA Witness Walters also referred to a comparison of the national average and median capital structure for electric utilities approved by regulatory commissions over the last several years.

The Settlement Agreement establishes the Parties' agreement that a capital structure consisting of 52.43% equity and 47.57% long-term debt is an acceptable compromise of the Parties' varying views on the appropriate capital structure to be utilized in order to set just and reasonable rates in this case.

Commission Discussion

The Settlement Agreement incorporates a capital structure that includes 52.43% equity and 47.57% long-term debt. Hearing Exhibit No. 6, pp. 7-9 (Settlement Agreement). All Parties support this capital structure within the context of the Settlement Agreement. The evidence of record supports this capital structure. It is within the range of capital structures included in the recommendations of the expert witnesses in this case and is identical to the recommendation of ORS Witness McGlone. It also reflects the actual capital structure of the Company as of August 31, 2022. After consideration of the evidence in the record, the Commission concludes that it is just and reasonable to approve the capital structure of 52.43% equity and 47.57% long-term debt as set out in the Settlement Agreement.

C. COST OF DEBT

Summary of the Evidence and Commission Discussion

The testimony of Witnesses Newlin, McGlone, and Rothschild all note that the Company's cost of debt is 3.77%. Hearing Exhibit No. 6, p. 7 (Settlement Agreement). No witness refuted the cost of debt in testimony. In addition, the Settlement Agreement establishes the Parties' agreement that a 3.77% cost of debt is appropriate in order to set just and reasonable rates in this case. *Id.* The evidence of record is uncontested, and the Parties all agree as evidenced by the terms of the Settlement Agreement. The Commission, therefore, approves the cost of debt of 3.77% as set out in the Settlement Agreement.

D. OVERALL RATE OF RETURN (ROR)

Summary of the Evidence and Commission Discussion

Based upon an ROE of 9.6%, a capital structure of 52.43% equity and 47.57% long-term debt, and a cost of debt of 3.77%, the overall ROR agreed to in the Settlement Agreement of 6.83% is also approved by the Commission. Hearing Exhibit No. 6, p. 21 and p. 7 (Settlement Agreement). This overall ROR will result in just and reasonable rates that are fair to the Company, ratepayers, and is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-20

(Excess Deferred Income Tax Mitigation)

The evidence in support of the findings of fact are found in the verified Application, Settlement Agreement, pleadings, the Testimony and Exhibits of DEP Witness Elliott (Direct, Rebuttal and settlement); ORS Witness Hyatt (Direct), and the entire record in this proceeding.

In the Company's last general rate case, the Commission approved the Company's request to flow back five categories of benefits resulting from the Tax Cuts and Jobs Act of 2017 to customers through an EDIT Rider. Order 2019-341, p. 110. Specifically, pursuant to the 2019 Settlement, the Commission permitted the Company to flow back to customers through the EDIT Rider the following five categories of benefits for customers: (1) Federal EDIT – Protected; (2) Federal EDIT – Unprotected, PP&E-related; (3) Federal EDIT – Unprotected, non-PP&E-related; (4) Deferred Revenue; and (5) North Carolina EDIT. *Id.* The Commission also required the Company to file annual updates to its EDIT Rider by March 31 for rider rates effective June 1. *Id.*

In its Application, the Company proposed to continue the annual EDIT Rider updates for the following three categories of benefits: (1) Federal EDIT – Protected; (2) Federal EDIT – Unprotected PP&E-related; (3) Federal EDIT – Unprotected, non-PP&E-related. Tr. 768.34:11-14. Additionally, in order to mitigate the impact of the base rate increase to customers and to allow the appropriate revenue recovery, the Company proposed to flow back to customers on an accelerated basis, Federal unprotected EDIT associated with PP&E.[7] Tr. 768.34:20-768.35:1. Specifically, the Company proposed to flow back the remaining portion of federal unprotected PP&E-related EDIT to customers over 2.17 years (26 months), beginning April 1, 2023. Tr. 768.35:7-10. This proposal reduced the number of years of amortization for federal unprotected EDIT associated with PP&E from 20 years[8] to 6.6 years and changed the annual EDIT revenue requirement to approximately $27,429,000. Hearing Exhibit 10. Tr. 768.36:1-2; Tr. 774.29:6-7. Company Witness Elliott asserted that the proposed change to the EDIT Rider was beneficial to customers because it partially offset the annual base rate increase by approximately $20,990,000. Tr. 768.9:13-15; Tr. 768.36:9-10; Tr. 774.29:7-9. In his Direct Testimony, ORS Witness Hyatt recommended that the Commission accept the Company's proposed accelerated flow back of the Federal unprotected EDIT associated with PP&E. Tr. 1032.6:12-13.

Pursuant to the Settlement Agreement, the Company agrees to accelerate the flow back of federal unprotected PP&E-related EDIT to customers beginning on April 1, 2023.

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[7] The Company did not propose to accelerate the return on Federal protected EDIT associated with PP&E or Federal unprotected non-PP&E-related EDIT.

[8] In the Company's last general rate case, the Commission approved the Company's proposal to flow back this portion of the Federal EDIT to customers over a 20-year period.

Hearing Exhibit No. 6, p. 8 (Settlement Agreement). As explained in Company Witness Elliott's Settlement Testimony, the Settlement Agreement reduces the original amortization period from 20 years to 6.6 years. Tr. 776.5:4-6. Elliott Settlement Exhibits 2 and 3, included in Attachment A to the Settlement Agreement (Hearing Exhibit No. 6, pp. 50-53), update the Company's proposed EDIT Rider to reflect the terms of the Settlement Agreement. Tr. 776.8:7-776.9. The total impact of the modifications results in an annual decrease of approximately $16.4 million in customer rates. Tr. 776.9:17-19. Witness Elliott testified that the annual EDIT Rider decrease will partially offset the annual base rate increase until the total Federal unprotected PP&E-related EDIT balance is fully flowed back to customers, which is expected to occur at the end of 2025. Tr. 776.5:6-8.

With the exception of the modifications agreed to by the Company in the Settlement Agreement, no party has objected to the flowback period embedded in the EDIT Rider proposal, and the Commission approves it, as modified by the Settlement Agreement, for the reasons outlined above. Hearing Exhibit No. 6, pp. 7-9 (Settlement Agreement).The Company's proposed EDIT Rider is just and reasonable and will result in rates that are just and reasonable and should be implemented. As shown in Hearing Exhibit No. 6, pp. 51-53, the appropriate annual revenue requirement for the EDIT Rider is an annual decrease of $16,426,000. The Company shall continue to file the EDIT Rider amounts, along with the spread to the classes and derivation of the rate, for each subsequent year with the Commission in this docket by March 31, for rider rates effective June 1. The Commission finds that the EDIT Rider, as modified by the Settlement Agreement, is just, reasonable and in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21-26

(Coal Ash Basin Closure Expense Adjustments – Coal Ash Regulatory Asset)

The evidence supporting these findings of fact is found in the verified Application; the Settlement Agreement; the Testimony and Exhibits of DEP Witnesses Elliott (Direct, Supplemental Direct, Second Supplemental Direct, Rebuttal, and settlement), Bednarcik (Direct and Rebuttal), Williams (Direct and Rebuttal), Rokoff (Direct and Rebuttal) and Fetter (Direct and Rebuttal); ORS Witnesses Seaman-Huynh (Direct and Surrebuttal) and Wittliff (Direct and Surrebuttal); and DCA Witness Borden (Direct and Surrebuttal); and the entire record in this proceeding.

Summary of the Evidence

In the Company's Direct case, it sought recovery of approximately $107,554,000[9] on a South Carolina retail basis incurred through August 31, 2022, in costs necessary to close its coal combustion residual (CCR) surface impoundments (CCR Costs). CCR, a byproduct of burning coal to produce electric power, is also referred to as "coal ash." Tr. 828.15:13. The Company's surface impoundments include ten coal ash basins located at DEP's coal-fired generation sites (both active and retired): the Robinson Ash Basin in South Carolina, and in North Carolina the East Ash Basin at Roxboro, the West Ash Basin at Roxboro, the Mayo Ash Basin, the Weatherspoon Ash Basin, the H.F. Lee Active Ash Basin, the Asheville 1964 Ash Basin, the Asheville 1982 Ash Basin, the Sutton 1971 Ash Basin, and the Sutton 1984 Ash Basin. Tr. 828.35:4–828.69:17. The focus of the testimony in this case from the Company, ORS, and other intervenors is with respect to these basins.

[9] Revised to $106,836,000 in the Company's Supplemental filing.

The Company's Direct case, principally through the testimony of Witness Bednarcik, describes the activities undertaken by DEP to close the CCR impoundments at issue and the costs associated with those activities. Tr. 828.35:4–828.69:17. Her testimony sets forth the Company's view that the costs were prudently incurred and recoverable, and this view is supported by the additional Testimony and Exhibits of Witnesses Williams, Rokoff, and Fetter. *See generally* Bednarcik Direct, Williams Direct, Rokoff Direct, and Fetter Direct.

ORS, through the Direct Testimony of Witnesses Seaman-Huynh and Wittliff, presented its view that a portion of the CCR Costs were incremental to the Federal CCR Rule, and were incurred as a result of the Company's obligation to comply with North Carolina laws and regulations, principally North Carolina's Coal Ash Management Act (CAMA). *See generally* Seaman-Huynh Direct, Wittliff Direct. Witnesses Seaman-Huynh and Wittliff recommended that the Commission disallow costs they viewed as being incurred in connection with CAMA compliance. According to the figures in Table 5 of Witness Wittliff's Direct Testimony, the disallowance is approximately 46% of the Company's requested recovery. Tr. 1030.4:2-4; Tr. 1028.63:1-8.

DCA, through the Direct Testimony of Witness Borden, did not present a specific disallowance amount, but encouraged the Commission to assess whether the Company should recover any of its CCR Costs. Tr. 906.4:13-18. Witness Borden further testified that if the Commission allowed the Company to recover its CCR Costs, then the DCA recommended that the Commission allow the Company to either (1) recover its CCR Costs without a return or (2) earn a return based on the seven-year treasury rate (3.87%). Tr. 906.18: 5-20.

Nucor Steel Witness LaConte focused her testimony on the amortization period proposed by the Company for CCR Costs but did not take a position on what costs the Company should be allowed to recover. Tr. 928.7:1-18. Witness LaConte recommended that the Company, at a minimum, extend the amortization period to 20 years. Tr. 928.8:6-18. Witness LaConte further recommended that should the Commission decide that "there should be a greater sharing of CCR costs between DEP and ratepayers, the Commission should allow DEP to earn a return at its weighted average cost of long-term debt on the unamortized balance[]." Tr. 928.6:10-15.

The Rebuttal Testimony of Company Witnesses Bednarcik, Williams, Rokoff, and Fetter responded to the Testimony of ORS Witnesses Seaman-Huynh and Wittliff as well as DCA Witness Borden, and, in turn, those Witnesses' Surrebuttal Testimony responded to the Company Witnesses' Rebuttal. *See generally* Bednarcik Rebuttal, Williams Rebuttal, Rokoff Rebuttal, and Fetter Rebuttal.

In the Settlement Agreement, the Settling Parties agreed to the following:

- As set forth in Section B Paragraph 11 of the Settlement Agreement, the Company agreed to a permanent, one-time $50,000,000 disallowance on a South Carolina retail basis of CCR Costs incurred through August 31, 2022. Hearing Exhibit No. 6, p. 9 (Settlement Agreement).
- As set forth in Section B Paragraph 12 of the Settlement Agreement, the Company agreed that in addition to the $50,000,000 permanent one-time disallowance referenced in the Section B, Paragraph 11 of the Settlement Agreement, the Company would permanently forego recovery in any future cases of any remaining coal ash costs sought by DEP but not allowed for

recovery by the Commission in DEP's prior rate case, Docket No. 2018-318-E. *Id.*

- As set forth in Section B Paragraphs 13-15 of the Settlement Agreement,[10] the Settling Parties further agreed as follows:
    - Subject to Section B Paragraphs 11 and 12, the Company will continue deferred accounting treatment for CCR Costs, which will include a debt return only, at the most recent Commission approved debt rate for the deferral period and rate base treatment during the amortization period, and the deferral will be subject to a review for reasonableness and prudency in the next general rate proceeding. Hearing Exhibit No. 6, p. 9 (Settlement Agreement).
    - Other than the permanently disallowed costs identified Section B Paragraphs 11 and 12, the disallowance of CCR Costs is solely related to the Settlement Agreement and shall have no precedential effect on the recoverability of CCR Costs or the continuation of deferral accounting treatment in future proceedings, and the Settling Parties reserve their rights on any other legal issues or to advance any other positions on coal ash in future cases. *Id.*
    - That the Parties would engage in good faith negotiations prior to January 1, 2030, to resolve all issues and claims in connection with

[10] *Hearing Exhibit No. 6, pp. 9-10 (Settlement Agreement).*

CCR Costs incurred by the Company after February 28, 2030, which shall not have any precedential effect and shall not impact or limit, in any way, a Settling Party's ability to advance in future proceedings any legal arguments, theories, positions, etc. regarding CCR Costs; and this provision does not place any obligation upon any Settling Party to resolve those issues and claims in a future proceeding, and each Settling Party maintains complete discretion to approve or reject any proposed settlement for those issues and claims in a future proceeding.

Commission Discussion

The Parties held widely divergent views as to the nature of CCR Costs and the propriety of recovery of those costs. The Parties addressed their divergent views in a comprehensive fashion and arrived at a compromise position in this proceeding, without prejudice (other than as specifically set forth in their Agreement) to their ability in a future case to put forth their views as they existed prior to their compromise for the purpose of settling this case. In this case, after consideration of the evidence on the whole record, the Commission concludes that it is just and reasonable and a fair balancing of the interests of the Company and its customers to approve the Settlement Agreement with respect to the CCR Costs. The result of this Agreement on this issue is in the public interest.

The Commission finds and concludes it is just and reasonable in light of all the evidence presented that the Company shall recognize a permanent, one-time $50,000,000 disallowance on a South Carolina retail basis of CCR Costs incurred through

August 2022 associated with ORS Witness Wittliff's recommended adjustments; that, in addition to the $50,000,000 disallowance of CCR Costs, the Company shall permanently forego recovery in any future cases of any remaining CCR Costs sought by the Company but not allowed for recovery by the Commission in Docket No. 2018-318-E; that the Company is authorized to continue deferred accounting treatment for its CCR Costs, with the deferral period to include a debt return only at the most recent Commission-approved debt rate, followed by rate base treatment during the amortization period; that the deferral will be subject to a review for reasonableness and prudency in the Company's next general rate proceeding; that the disallowance of CCR Costs is solely related to this Settlement Agreement and shall have no precedential effect on the recoverability of CCR Costs or the continuation of deferral accounting treatment in future proceedings and that the Parties reserve all rights to advance any and all legal positions regarding CCR Costs in future proceedings; and that prior to January 1, 2030, the Settling Parties shall engage in good faith negotiations to resolve all issues and claims in connection with CCR Costs incurred by the Company after February 28, 2030.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

(Expense Adjustments)

The evidence supporting this finding of fact is found in the verified Application; the Settlement Agreement; the Testimony and Exhibits of DEP Witnesses Callahan (Settlement) Elliott (Direct, Supplemental Direct, Second Supplemental Direct, Rebuttal, and Settlement), Ray (Rebuttal), Riley (Direct and Rebuttal), Spanos (Direct and Surrebuttal) Stewart (Direct), Turner (Direct and Rebuttal); ORS Witnesses Bickley (Direct), Briseno (Direct and Revised Surrebuttal), Hipp (Settlement), Rabon (Direct)

Sandonato (Direct); Seaman-Huynh (Direct and Surrebuttal), Wittliff (Direct and Surrebuttal); Nucor Witness LaConte (Direct); and DCA Witness Borden (Direct and Surrebuttal); and the entire record in this proceeding.

The Settling Parties reached a Settlement Agreement with respect to the expense adjustment issues presented by the Company's Application, including those arising from the Supplemental and Rebuttal testimony and exhibits. The Settlement Agreement provides that with the exception of the expense adjustments outlined in Section B Paragraphs 16–35 of the Settlement Agreement (Hearing Exhibit No. 6, pp. 10-16), all Parties agree to all other expense adjustments as recommended by ORS, and all other necessary fallout adjustments that changed due to the Settlement Agreement. Settlement Agreement at Section B Paragraph 36. Hearing Exhibit No. 6, pp. 10-16 (Settlement Agreement). The Settling Parties further agreed that the proposed accounting and pro forma adjustments appended to the Settlement Agreement as Attachment A are fair and reasonable and should be adopted by the Commission for ratemaking and reporting purposes. Settlement Agreement at Section B Paragraph 37. Hearing Exhibit No. 6, p. 17 (Settlement Agreement). The Commission finds that the terms of the Settlement Agreement relating to the Expense Adjustments in Paragraphs 16 through 37 (Hearing Exhibit No. 6, pp. 10-17) are a fair and reasonable resolution of these issues and the result of compromise among the Settling Parties and are therefore approved. The expense adjustments outlined in Section B Paragraphs 16 through 35 of the Settlement

Agreement,[11] and our findings and conclusions related to those specific adjustments, are discussed in more detail below.

Coal Inventory

As part of the Company's pro forma adjustments, DEP Witness Rachel Elliott included an adjustment to increase the Company's coal inventory at the end of the Test Period to reflect a targeted 40-day full load burn (FLB) for each of the coal generating plants. Tr. 768.31:10-14. In his Direct Testimony, ORS Witness Bickley recommended that the Company's coal inventory balance be adjusted to reflect a 35-day inventory based on a 100% FLB, rather than the 40-day inventory based on a 100% FLB requested by the Company. Tr. 1022.21:5-21.

In her Rebuttal Testimony, Company Witness Turner testified that the Company made a pro forma adjustment increasing its actual coal inventory at the end of the Test Period to reflect a targeted 40-day 100% FLB because it is prudent to continue to operate under the currently approved 40 days full load burn inventory target to ensure adequate coal supply for the benefit of customers. Tr. 888.5:5-7. Witness Turner stated that the ORS's recommendation fails to contemplate the factors that impact a reliable fuel supply—including delivery and/or supply risks and volatility in coal generation demand. Tr. 888.4:17-19. She concluded that a 40-day FLB inventory target allows DEP's coal plants to provide a fuel-secure source of generation in the event of supply disruptions. Tr. 888.2:20-22.

[11] Hearing Exhibit No. 6, pp. 10-16 (Settlement Agreement).

In his Surrebuttal Testimony, ORS Witness Bickley reiterated that customers should not pay for a 40-day FLB target that does not align with the Company's actual performance data. Tr. 1054.11: 9--1054.12:22.

Section B Paragraph 17 of the Settlement Agreement provides that the Parties accept the ORS recommendation to limit coal inventory in base rates to 35 days for ratemaking purposes. Company Witness Callahan and ORS Witness Hipp supported this provision through their Testimony in support of the Settlement Agreement. Tr. 649.5:6-9; Tr. 983.2:14-983.3:8.

Commission Discussion

No other party offered any evidence addressing this issue. The Commission finds and concludes it is just and reasonable in light of all the evidence presented, for purposes of this proceeding, that the Company limit coal inventory in base rates to 35 days for ratemaking purposes as described in the Direct Testimony of ORS Witness Bickley.

End-of-Life Nuclear Reserve Adjustment

As part of the Company's pro forma adjustments, DEP Witness Rachel Elliott included an adjustment to the Company's end-of-life nuclear reserve associated with nuclear materials and supplies and nuclear fuel. Tr. 768.19:4-10. In his Direct Testimony, ORS Witness Bickley noted the Company included a nuclear fuel escalation rate of 2%. Tr. 1022.5: 17-1022.6:10. Witness Bickley recommended removal of the 2% nuclear fuel annual escalation rate because it is based solely on an estimate and is therefore not known and measurable nor did the Company provide an adequate basis to include the escalation rate in nuclear fuel cost in the end-of-life nuclear reserve. Tr. 1022.8:15-1022.9:10.

In their Rebuttal Testimony, Company Witnesses Ray and Elliott testified that the approach of averaging recent historical variation in nuclear fuel costs to apply a 2% escalation to such costs in future years is reasonable and conservative and allows the customers who are currently served by and benefit from the nuclear units to pay for end-of-life costs over a period of time to avoid a significant increase in costs as the nuclear units are retired. Tr. 864.3:3-5.

In Surrebuttal Testimony, ORS Witness Bickley raised the potential for nuclear fuel prices to remain the same or decrease in the future and noted that the annual amortization expense can be reviewed and adjusted if needed based on updated estimated end-of-life costs in future general rate case proceedings. Witness Bickley stated that the escalation is not known and measurable and therefore should be disallowed. Tr. 1054.3:3-1054.6:2.

Section B Paragraph 18 of the Settlement Agreement provides that the Parties accept the ORS recommendation to remove the fuel escalation factor from the End-of-Life Nuclear Reserve Adjustment. Company Witness Callahan and ORS Witness Hipp supported this provision through their testimony in support of the Settlement Agreement. Tr. 649.5:6-9; Tr. 983.1:13-983.2:13; 983.5:5-8.

Commission Discussion

No other party offered any evidence addressing this issue. The Commission finds and concludes it is just and reasonable in light of all the evidence presented, for purposes of this proceeding, that the Company should remove the fuel escalation factor from the End-of-Life Nuclear Reserve Adjustment as described in the Direct Testimony of ORS Witness Bickley.

Board of Director Expenses

ORS Witness Rabon testified in support of ORS Adjustment 33, which recommends a disallowance of 50% of the Company's costs associated with Duke Energy Corporation's (Duke Energy) Board of Directors compensation, 50% of expenses associated with directors and officers liability insurance, and 50% of all remaining Board of Director expenses (except for aviation costs). Tr. 1034.6:20-23. ORS Witness Rabon acknowledged that members of the Company's Board of Directors have "responsibilities to meet the needs of both shareholders and customers." Tr. 1034.7:7-8. As such, ORS Witness Rabon testified that ORS' Adjustment 33 is an appropriate allocation of costs between shareholders and customers because "[i]t is not reasonable for customers to contribute 100% of the revenue requirement" given the duty owed to both customers and shareholders. Tr. 1034.7:13-14. ORS Witness Rabon cited several other jurisdictions where "similar adjustments have been recommended and approved . . . ." which include "New Mexico, Nevada, Connecticut, Arkansas, North Carolina, Oregon, Arizona, California, Florida, and Washington." Tr. 1034-12:7-9.

Commission Discussion

Section B, Paragraph 16 of the Settlement Agreement adopts ORS Adjustment 33 in its entirety. All Parties have agreed to support this adjustment. After consideration of the evidence in the record, the Commission concludes that it is just and reasonable to approve the disallowance as set out in the Settlement Agreement.

Executive Compensation and Incentive Compensation

Executive Compensation

In its Application, the Company made an adjustment to remove 50% of the base salaries and incentives of the top five Duke Energy executives with the highest level of compensation (i.e., the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Chief Legal Officer, and Duke Energy Carolinas Executive Vice President) allocated to DEP during the Test Year. Witness Elliott indicated that although the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, for purposes of this case, it made an adjustment to this item. Tr. 768.16:8-12; *see also* Hearing Exhibit 10, p. 47). However, ORS recommended an adjustment to remove 50% of the base salary and restricted stock units included in long-term incentives (LTI) associated with these employees, as well as 50% of the benefits and payroll taxes associated with the executives' salaries that the Company did not remove as part of its adjustment. Tr. 1042.3:14-18. ORS Witness Sullivan testified the additional adjustments were based on the executives and officer's fiduciary duty to the Company's shareholders and owners; however, as executive compensation provides benefits to shareholders and customers alike, cost sharing was appropriate. Tr. 1042.4:4-15. Witness Sullivan also testified that ORS's adjustment was consistent with prior rulings from the Commission. Tr. 1042.4:19-1042.5:13. In his Rebuttal Testimony, Company Witness Stewart, while disagreeing with Witness Sullivan's reasoning, agreed that for purposes of streamlining this case, the ORS adjustment was acceptable. Tr. 884.19:3-8. The Company's acceptance of the ORS position for purposes of this case is memorialized in Section B Paragraph 20 of the Settlement Agreement.

ORS also sought in its Direct Testimony to disallow non-qualified pension expense and executive deferred compensation. (ORS Adjustments 8 and 34; Tr. 1042.12-1042.20. Company Witness Stewart responded in his Rebuttal Testimony indicating the

Company's disagreement with these adjustments and the reasons therefor. Tr. 884.19:20-884.20:10. However, in Section B Paragraph 19 of the Settlement Agreement, the Settling Parties agreed, to these adjustments and removal of these costs from the Company's cost of service. As indicated in the Settlement Agreement, the Parties agreed to these concessions for purposes of this case only, and without prejudice to any Party's position in future cases.

Incentive Compensation

The Company included in its Application an adjustment to normalize wages and salaries, related employee benefits costs, and changes in related payroll taxes to reflect annual levels of costs as of May 31, 2022. The adjustment also restated variable short- and long-term incentive pay to 2022 target levels. Tr. 768.16:14-18. . A description of Duke Energy's compensation philosophy, along with the details of its long-term and short-term incentive pay programs, including the metrics applicable to both programs, was presented in the Direct Testimony of DEP Witness Stewart. Tr. 882.8:882.25. The incentive pay metrics include Earnings Per Share (EPS) and Total Shareholder Return (TSR), which are tied to the Company's financial performance and growth.

ORS proposed an adjustment that would exclude the incentive compensation plan costs associated with the financial metrics tied to EPS and TSR. Tr. 1042.5:18-1042.6:14. This recommendation was also proposed by DoD/FEA Witness Gorman. Tr.918.14:3-5. The ORS and DoD/FEA position was principally grounded in these Witnesses' view that financial metrics are more aligned to the Company's shareholders than its customers. Tr. 918.10:19-918.15:24; 1042.11:14-15; 1042.20:18. More specifically, ORS Witness Sullivan testified that payments for financial goals are not certain, may be influenced by factors outside of the Company's control, should not be borne by customers but rather through increased shareholder earnings, and the inclusion of these financial metrics in rates shifts the risk from shareholders to customers. Tr. 1042.11:9-17. Witness Sullivan also testified that ORS's recommendations were consistent with prior orders from the Commission and reflected cost recovery treatment of EPS and TSR for other jurisdictions in which the Company and other Duke Energy affiliates operate. Tr.1042.15-1042.20.

In his Rebuttal Testimony, Company Witness Stewart took issue with the recommendations put forth by ORS and DoD/FEA concerning adjustments to incentive compensation, principally on the grounds that no party had objected to the overall levels of compensation for the Company's employees; instead, they second-guess the business judgment of the Company in designing its compensation system and neither ORS, nor DoD/FEA explain why their arguments, which were rejected in the last rate case, should be accepted by the Commission in this case. Tr. 884.2:7-22. Witness Stewart also testified that both ORS Witness Sullivan and DoD/FEA Witness Gorman assume there is a divergence of interest between customers and shareholders that automatically makes any incentive compensation based on the financial performance of the Company, somehow harmful to customers, an assumption that DEP contends is false. Tr. 884.4:1-6.

Commission Discussion

The Parties, in the Settlement Agreement, have resolved the issue of executive and incentive compensation in a manner that reflects a reasonable compromise in this case and will result in rates that are just and reasonable. The Commission finds and concludes it is just and reasonable in light of all the evidence presented to accept in this case the expense reductions set forth in Section B Paragraphs 19, 20, and 28 of the

Settlement Agreement.

Plant and Accumulated Depreciation Updates

In its Application, through Company Witness Elliott's Exhibit 1 (Hearing Exhibit No. 10, pp. 1-13), DEP proposed to adjust depreciation and amortization expense by $12,285,000, income tax expense by ($3,065,000), amortization of investment tax credits by ($3,000), and accumulated depreciation and amortization by ($12,285,000) to annualize depreciation expense on plant balances as of December 31, 2021. (Hearing Exhibit No. 10, pp. 1-13). Company Witness Elliott explained that the depreciation rates underlying the composite calculations were based on the 2018 Depreciation Study and 2020 Nuclear Depreciation Study filed with the Commission in Docket No. 2021-226-E and are supported by Company Witness Nicholas Speros. Tr. 768.33:15-18; (Hearing Exhibit No. 10, pp. 1-13).

In her Supplemental Direct Testimony and Exhibits filed on September 23, 2022, Company Witness Elliott updated for actual post-test year plant additions through the capital cut-off of August 31, 2022. Tr. 770.6:4:4-10; Hearing Exhibit No. 10, pp. 245-258.

ORS Witness Radley testified that ORS proposes an additional adjustment to plant in service, accumulated depreciation and amortization, and depreciation and amortization expense to account for actual plant additions, retirements, and accumulated depreciation and amortization as of August 31, 2022. Tr. 1014.3:13-1014.5:28. Specifically, ORS proposed to adjust depreciation and amortization expense by $14,937,000, income tax expense by ($3,727,000), amortization of investment tax credits by ($3,000), and accumulated depreciation and amortization by ($14,937,000) to annualize depreciation and amortization expense. Tr. 1014.3:20-23. She explained that ORS's adjustment annualized depreciation and amortization on plant balances as of August 31, 2022, to align with ORS Adjustment 15 regarding post-Test Year additions, retirements, and accumulated depreciation as of August 31, 2022. Tr. 1014.3:23-1014.4:1. ORS also proposed an additional adjustment to depreciation and amortization expense to incorporate the recommendations of ORS Witness Garrett regarding the adjustment of the Company's depreciation rates reflected in ORS Adjustment 35. Tr. 1014.4:2-4.

On Rebuttal, Company Witness Elliott disagreed with the ORS's calculation of the additional adjustment to accumulated depreciation and amortization for the impact of annualizing the depreciation and amortization expense, as well as ORS's underlying reasons for recommending such adjustment. Tr. 774.1-774.13:9. In Elliott Rebuttal Exhibit 5 (Hearing Exhibit No. 10, pp. 472-475), Company Witness Elliott provided an adjustment to accumulated depreciation and amortization of ($4,486,000) for the annualization of depreciation and amortization expense as of August 31, 2022, using the 12 months ended August 31, 2022. She testified the calculation uses the same methodology as in the Company's last North Carolina rate case. Tr. 774.13:10-15

In her Surrebuttal Testimony, ORS Witness Radley stated that ORS disagrees with Company Witness Elliott's recommendation to continue DEP's past and currently recommended approach to post-Test Year adjustments for plant additions, without a corresponding adjustment for post-Test Year retirements and accumulated depreciation, but that ORS accepts Company Witness Elliott's calculation for the additional adjustment to accumulated depreciation and amortization for the impact of annualizing depreciation and amortization expense. Tr. 1050.1:14-1050.2:2.

Section B Paragraph 23 of the Settlement Agreement provides that the Parties accept the ORS recommendation in its Revised Surrebuttal Testimony and Exhibits to update plant and accumulated depreciation inclusive of retirements through August 2022. Company Witness Callahan and ORS Witness Hipp supported this provision through their Testimony in support of the Settlement Agreement. Tr. 643:22-644.3; 649.9:1-4; 983.1:13-14; 983.2:3-13; 983.5:6-8.

Commission Discussion

All Parties support this position of the Settlement Agreement and this update represents a reasonable compromise by the Parties when considered against the comprehensive resolution this concession helped, in part, to achieve. After consideration of the evidence in the record, the Commission concludes that it is just and reasonable to approve the update to plant and accumulated depreciation inclusive of retirements through August 2022 for ratemaking purposes as described in the Revised Surrebuttal Testimony of ORS Witness Briseno.

Adjustments Relating to Deferrals

Background On the Company's Requests for Deferral Accounting

The Company proposed to begin amortizing several deferred costs for which the Commission had previously granted accounting orders permitting the Company to defer the costs for consideration for cost recovery in the Company's next rate case. The Company requested that the deferrals be included in rate base during the amortization period and that the Company be permitted to recover its weighted average cost of capital on the unamortized balance during the amortization period. These specific accounting adjustments include deferred costs for the following:

- **DEP Adjustment #19:** SC4010 - Amortize Deferred Environmental ARO (Asset Retirement Obligation) Costs[12]

- **DEP Adjustment #21: SC5020 –** Amortize rate case costs

- **DEP Adjustment #22: SC5030 –** Amortize deferred environmental non-ARO costs[13]

- **DEP Adjustment #23: SC5040** – Amortize Deferred Grid Costs[14]

- **DEP Adjustment #25: SC5100** – Amortize deferred SC AMI Costs[15]

- **DEP Adjustment #26: SC5110 –** Amortize deferred Asheville Combined Cycle Costs[16]

- **DEP Adjustment #27: SC5140 –** Amortize deferred S.C. Act No. 62 Costs[17]

In addition to the accounting deferrals noted above and already approved for deferral by the Commission, in its Application, the Company also requested an accounting order to: (1) continue the deferral for coal ash basin closure compliance costs after the cut-off date for this rate case of August 31, 2022, discussed further herein; (2) establish a regulatory asset for the early retired Roxboro Wastewater Treatment Plant for the remaining net book value, and permission to defer to this regulatory asset any dismantlement or other related costs, net of salvage, related to the retirement; and (3) to record to a regulatory asset the incremental increase in depreciation expense resulting

[12] Deferral approved in Order No. 2019-341 in Docket No. 2018-318-E. This deferral is addressed herein in the Evidence and Conclusions for Findings of Fact Nos. 21-27.
[13] *Id.*
[14] *Id.*
[15] Deferral approved in Order No. 2019-454 in Docket No. 2018-205-E and continuation approved in Docket No. 2018-318-E.
[16] Deferral approved in Order No. 2020-421 in Docket No. 2020-144-E.
[17] Deferral authorized by Section 15 of Act 62.

from the 2021 Depreciation Study from the effective date of the depreciation rates until the Company's next South Carolina general base rate case.[18] Application ¶¶ 38-41; Tr. 768.41:13-21. ORS and Nucor Steel proposed different treatment for the deferrals which the Company opposed. The general differing positions of the Company and the ORS in regard to deferrals are summarized below and the final agreed-upon treatment for each deferral pursuant to the terms of the Settlement Agreement is outlined further herein.

Company Position on Deferrals

The Company takes the position that it should be allowed to earn a return on its prudently incurred deferred costs both during the deferral period and during the amortization period. DEP Witness Riley supported the Company's position on deferrals and testified that when utility investors supply the funding for expenditures prior to recovery from customers, a return is generally permitted on such a regulatory asset until recovery has occurred. Tr. 866.5:7-14. He explained that recovery of the investment means the investor receives full cost recovery of each dollar invested. Further, he testified that the investor would typically receive a return on its investment until the balance has been recovered to account for the time value of the money to make the investor whole for its investment. *Id.*, 15-19. Witness Riley explained that to the extent that a utility incurs a cost of providing service that is unanticipated or at a level that was not recovered in existing rates, it must utilize its own funds (provided by investors) to pay for such costs. He testified that typically, operations and maintenance costs that are considered

[18] This deferral request was resolved by the Settlement Agreement as discussed in further detail in the Depreciation section below.

recoverable from ratepayers are recovered quickly (i.e., in the short-term (within a year)), as it is the current ratepayers that benefitted from such expenditures/service. Tr. 866.5:20-866.6:2. If recovery of these costs is deferred to the future (e.g., beyond a year), he testified that customers are essentially receiving a loan from the utility since, by definition, these costs are not being recovered in current rates, and the customers will instead pay for the utility's expenditure over a period of time rather than at the point the utility incurs the expenses. Tr. 866.6:2-7. As a result, DEP takes the position that cost deferrals (for costs deemed prudently incurred) should receive a carrying charge (i.e., a return) to compensate a utility investor for the use of capital. *Id.*, 7-9. Witness Riley further testified that cost deferrals are treated in a similar manner as invested capital for ratemaking purposes. *Id.*, 10-11.

In terms of the cut-off date to be used for the regulatory asset balances, with the exception of the Act 62 costs,[19] the Company calculated the regulatory asset balances through March 31, 2023, the day before the anticipated rates effective date in this case. The Company believes that updating the deferred costs through this period more accurately reflects the total regulatory asset balance to be recovered when new rates become effective and would be the most accurate basis for setting the appropriate amortization expense. Tr. 774.19:10-23.

While the Company notes there are no prescribed guidelines for setting amortization periods, it states that there needs to be a balance and consideration of the

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[19] The Company stated that it did not include Act 62 costs beyond the capital cut-off in this case because the balance consists of costs that are not known and measurable. Tr. 774.20:3-4.

collective impact of amortization periods on both customer rates and the Company's cash flow. The Company's position is that its proposed amortization periods in this case, as discussed further herein, collectively strike the appropriate balance. Tr. 774.3:2-6.

ORS Position on Deferrals

ORS believes that, in general, utilities should be allowed to use deferral accounting as a tool in limited situations where the utility clearly demonstrates that: (1) the costs in question are unusual or extraordinary in nature and (2) absent deferral, the costs would have a material impact on the utility's financial condition. Tr. 1012.3:16-19. Once deferral accounting is authorized, it is ORS's position that costs considered for deferral, including deferred carrying costs proposed on those expenditures, should be based upon and limited to incurred costs. Tr. 1012.3:20-22. Regarding allowances of carrying costs, ORS does consider the timing of expenditures between rate cases. Tr. 1012.3:22-1012.4:1. Finally, for the costs that are unusual or extraordinary, material and incurred, the underlying costs included in the deferral must also meet reasonableness and prudency standards. Tr. 1012.4:1-3

ORS's recommendation on deferrals in this docket primarily relates to the rate used to calculate carrying costs during the deferral period. Tr. 1012.4:4-5. The Company calculated the carrying costs it has requested using the Company's previously approved weighted average cost of capital (WACC). The WACC rate includes a cost of debt component and a cost of equity component. *Id.*, 5-7. Unless otherwise ordered, ORS recommends that carrying costs during the deferral period should be calculated using the Company's previously approved cost of debt rates in effect at the time of the deferrals cost being incurred and not the WACC rate. ORS recommends excluding the equity return portion of the WACC when calculating carrying costs during the deferral period. *Id.*, 7-11. ORS acknowledges that at the point in time deferrals are included in rates the unamortized balances may, at the discretion of the Commission, be allowed a full WACC return by being placed into rate base. Tr. 1012-4:21-1012.5:1.

ORS's recommendation to exclude the equity component of the WACC rate and to use the Company's previously approved cost of debt rate for calculating carrying costs during the deferral period is based on two principles. Tr. 1012.4:12-14. First, since deferrals represent costs that are unusual, extraordinary and material in nature, and the costs included in deferrals occur between rate case filings, it is ORS's position that allowing carrying costs at a full WACC rate disincentivizes companies to pursue recovery of costs through the traditional rate case process in a timely manner, which limits the ultimate cost to customers. Tr. 1012.4:14-18. Additionally, a carrying cost rate lower than WACC during the deferral period incentivizes companies to continue to prudently manage the growing levels of underlying deferred expenditures until the balances are included in timely rate case applications. ORS acknowledges that at the point in time deferrals are included in rates the unamortized balances may, at the discretion of the Commission, be allowed a full WACC return by being placed into rate base. Tr. 1012.4:19-1012.5:1. However, during the deferral period, ORS believes its position provides effective incentives as discussed above. ORS maintains its position is also reasonable; it is not less than compensatory for the Company because it receives both a return of and return on the underlying costs deferred at the Company's previously approved cost of debt rate during the deferral period. Tr.1012.5:1-5. Second, ORS argues that the Company's previously approved cost of debt rate represents an objective standard for setting a reasonable carrying cost rate to use during the deferral period and is supported by Generally Accepted Accounting Principles. *Id.*, 6-8. ORS recommends that carrying costs be calculated using the Company's previously approved cost of debt, and not the full cost of capital, during the deferral period and that the Commission not allow rate base treatment during the amortization period for certain regulatory assets – namely, S.C. No. Act 62 costs, rate case expenses, and the Roxboro Wastewater Treatment Plant. Tr. 774.14: 9-15.

ORS also recommended utilizing an August 31, 2022, cut-off for all of the regulatory asset balances. In his Revised Surrebuttal Testimony, ORS Witness Briseno stated that ORS has limited the balance of the deferrals to the same point in time as the capital cut-off (August 31, 2022), which represents an objective point in time to align with the plant in service and accumulated depreciation updates proposed by ORS in this case. Tr. 1048.10:11-13. He stated that ORS acknowledges the Company included amounts for depreciation, property taxes, and carrying costs in its deferral calculations for the months of September 2022 through March 2023 to correspond with when new rates will go into effect. He further testified that mathematically speaking, ORS does not take issue with the Company's calculations for the months of September 2022 through March 2023, and that ORS does not object to the Company continuing amortizing the deferrals beyond ORS's proposed amortization periods in this case in order to recover the remaining costs the Company calculated for the months of September 2022 through March 2023, in order to minimize costs to customers in this case. Tr. 1048.10:14-21.

ORS generally recommends that the amortization period should align with the life or remaining life of the underlying assets[20] or for those deferrals not tied to an underlying asset such as rate case expense and Act 62 costs, for the period over which the expenses were incurred.

DEP Adjustment #26: SC5110 – Amortize deferred Asheville Combined Cycle Costs

In Docket No. 2020-144-E, the Company petitioned for approval for regulatory asset treatment for certain post in service costs being incurred in connection with the Asheville Combined Cycle (CC) plant, which the Commission approved in Order No. 2020-421. Tr. 768.29:19-21; 768.30:5-6. In its Application in this case, the Company made a pro forma adjustment to amortize the Asheville CC regulatory asset balance over a ten-year period, and included the balance, net of one-year of amortization and taxes, in rate base. Tr. 768.30:11-14. In her Supplemental Direct Testimony, Company Witness Elliott testified that the Company had updated the Asheville CC deferred balance amortization to reflect the actual costs and savings through August 31, 2022, noting that there were no additional plant additions to consider above what was reflected in the Company's initial filing. Tr. 770.8:6-10.

In his Direct Testimony, ORS Witness Briseno proposed an adjustment to the Asheville CC regulatory asset to remove all deferred equity returns included by the Company in the deferral balance, utilized a cut-off of the deferral balance as of August

[20] Nucor Steel Witness LaConte also testified that the costs should be recovered over the same time period as the asset's underlying life to be consistent with generational equity, in that, to the maximum extent possible, the costs should be recovered from customers that benefit from the facilities, consistent with how utility assets are depreciated. Tr. 928.11.

2022, calculated the deferred return using the Company's previously approved cost of debt, and the 37-year amortization period recommended by ORS Witness Bickley. Tr. 1012.20:8-12. Nucor Witness LaConte also recommended a 37-year amortization period for this deferral. Tr. 928.6:19-21; 928.13:5-6; 930.7:9-11. The Company opposed these adjustments for the reasons previously discussed. Tr. 774.14:15-18; 868.4:4-868.9:8. ORS also adjusted for a small correction the Company identified during discovery related to incremental operations & maintenance expense, which the Company did not oppose. Tr. 774.6:5-10.

Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues between the Parties regarding the Asheville CC regulatory asset. Section B Paragraph 21 of the Settlement Agreement provides that the Settling Parties agree that the appropriate amortization period for the Asheville CC regulatory asset is 37 years, and the deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period, and that the deferral will include depreciation, property taxes, and returns through March 2023.

Commission Discussion

The Commission finds and concludes it is just and reasonable in light of all the evidence presented that the appropriate amortization period for the deferred expenses for the Asheville CC Project is 37 years; the deferral shall include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period; and that the deferral will include depreciation, property taxes, and returns through March 2023.

DEP Adjustment #22: SC5030 – Amortize deferred environmental non-ARO (active) costs

In the Company's last general rate case, the Commission approved the Company's request for continuation of the regulatory asset treatment for the environmental non-ARO costs related to continued plant operations placed in service on or after January 1, 2019, with a carrying cost on capital-related costs only. Tr. 768.26:8-16. The Company included a pro forma adjustment in this case to amortize the balance related to these non-ARO environmental costs over a three-year period and include the cost of the balance, net of one year of amortization and taxes, in rate base. Tr. 768.26:21-768.27:2.

ORS Witness Wittliff recalled his testimony in Docket No. 2018-318-E and his recommendation adopted by the Commission that none of the non-ARO CCR Costs be disallowed. Tr. 1028.11:12-14. Witness Wittliff further recommended that the non-ARO CCR Costs incurred by the Company from October 1, 2018, through August 31, 2022, to close the CCR basins at Plants Roxboro and Mayo be recovered by the Company. Tr. 1028.60:12-14. ORS Witness Seaman-Huynh recommended that the non-ARO regulatory asset be amortized over a period of seven years. Tr. 1030.5:21-1030.6:2. The Company agreed with Witness Wittliff's and Witness Seaman-Huynh's non-ARO CCR Costs recommendations.

Nucor Steel Witness LaConte did not take a position on what CCR Costs the Company should be allowed to recover. Tr. 928.7:16. Instead, Witness LaConte focused her testimony on the amortization period proposed by the Company. Witness LaConte noted that the Company proposed to amortize its non-asset retirement obligation coal ash basin closure costs over three years. Tr. 928.5:16-18. Witness LaConte testified that the proposed amortization period was too short and resulted in intergenerational inequity "whereby customers today would shoulder the burden of paying for CCR costs that are a result of decades of accumulated coal ash expense by prior customers." Tr. 928.6:1-4. Witness LaConte recommended that the Company, at a minimum, extend the amortization period to 20 years, while earning its full, weighted average cost of capital return. *Id.*, 5-9. Witness LaConte further recommended that should the Commission decide that "there should be a greater sharing of CCR costs between DEP and ratepayers, the Commission should allow DEP to earn a return at its weighted average cost of long-term debt on the unamortized balance[]." *Id.*,10-14.

DCA presented the testimony of Eric Borden. Witness Borden encouraged the Commission to assess whether the Company should recover any of its CCR Costs. Tr. 906.7:29-30; 906.12:14-906.13:6; 906.18:9. Witness Borden testified that if the Commission allowed the Company to recover its CCR Costs, that it should explore cost recovery mechanisms other than regulatory asset treatment proposed by the Company. Tr. 906.7:27-28; 906.13:5-1906.16:14. Witness Borden opined that the Company's CCR Costs at its active coal-fired plants were more akin to operation and maintenance expenses than capital expenditures, and thus not appropriate for regulatory asset accounting treatment. Tr. 906.7:16-17; 906.15:1-6. Witness Borden recommended that the Commission allow the Company to either (1) recover its CCR Costs without a return, or (2) earn a return based on the three-year treasury rate (4.23%). Tr. 906.18:14-16.

The Company opposed these adjustments recommended by the intervenors for the reasons previously discussed. Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues between the Parties regarding the non-ARO CCR Costs. Section B Paragraph 22 of the Settlement Agreement provides that for the CCR non-ARO regulatory asset, the Settling Parties agree that (a) the Company will increase the amortization period from three (3) years to seven (7) years, (b) the deferral period will include a debt return only, at the most recent Commission-approved debt rate, followed by rate base treatment during the amortization period, and (c) the deferral will include depreciation and return on known investment balance through March 2023.

Commission Discussion

The Commission finds and concludes it is just and reasonable in light of all the evidence presented that the Company shall amortize the regulatory asset balance for its non-ARO CCR Costs. The Company shall earn a debt return only, at the most recent Commission-approved debt rate, during the deferral period and receive rate base treatment during the amortization period. The non-ARO CCR Costs deferral shall include depreciation and return on known investment balance through March 2023.

DEP Adjustment #23: SC5040 – Amortize Deferred Grid Costs

In the Company's last rate case, the Commission approved regulatory asset treatment for Grid Improvement Plan (GIP) costs as stipulated by the Company and the ORS. Tr. 768.27:4-6. In its Application in this case, the Company made a pro forma adjustment to amortize the Grid Improvement Plan regulatory asset balance over a five-year period and include the balance, net of one-year of amortization and taxes, in rate base. Tr. 768.27:17-19. In her Supplemental Direct Testimony, Company Witness Elliott testified that the Company had updated the Grid Improvement Plan deferred balance amortization to reflect the actual Grid Improvement Plan costs and plant additions through

August 31, 2022, and to include an accounting true-up related to 2022 installation operating and maintenance costs that were inadvertently excluded from the Company's initial filing. Tr. 770.7:13-770.8:2.

In his filed Direct Testimony, ORS Witness Briseno proposed an adjustment to the Grid Improvement Plan regulatory asset to remove all deferred equity returns included by the Company in the deferral balance, utilized a cut-off of the deferral balance as of August 2022, calculated the deferred return using the Company's previously approved cost of debt, and the 29-year amortization period recommended by ORS Witness Sandonato. Tr. 1012.18:12-16. Nucor Steel Witness LaConte testified that the expected depreciable life for DEP's grid investments ranges from 45-75 years and recommended an amortization period of 55 years. Tr. 928.12:15-928.13:2. The Company opposed these adjustments for the reasons previously discussed. Tr. 868.4:14-868.9:8.

Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues between the Parties regarding the Grid Improvement Plan deferred costs. Section B Paragraph 24 of the Settlement Agreement provides that the Settling Parties agree that the appropriate amortization period for the Grid Improvement Plant regulatory asset is 17 years and the deferral will include a debt return only (at the most recent Commission-approved debt rate) for the deferral period and rate base treatment during the amortization period, and that the deferral will include depreciation, property taxes, and returns through March 2023. The Settling Parties also agree to the continuation of the deferred accounting treatment for Grid Improvement Plan investments until the rates effective date in the Company's next general rate case and that Construction Work In Progress for Grid Improvement Plan Investments will not be included in rate base in this case. Settlement Agreement at Section B Paragraph 24(d).

On August 24, 2022, the Company requested an extension to the accounting order for ongoing GIP costs in Docket No. 2022-281-E which is currently pending before this Commission. As part of the Settlement Agreement, the Settling Parties agree it is appropriate to consolidate Docket No. 2022-281-E with this docket and to resolve the Company's request to continue the Grid Improvement Plan costs deferral in Docket No. 2022-281-E through this Settlement Agreement. *Id.* The Parties further agreed that grid investments and any continuation of deferral accounting treatment will be subject to a review for reasonableness and prudency in the next general rate proceeding. Settlement Agreement at Section B Paragraph 24(e). The deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period. *Id.* Finally, the Settling Parties agreed that the Company will identify, quantify and record to the GIP deferred account incremental savings to the Company resulting from GIP expenditures that are placed into the regulatory asset. Settlement Agreement at Section B Paragraph 24(f). These savings may include, but are not limited to, reductions in operating expenses, improvements in revenue assurance, increased conservation, and reductions in peak demand. *Id.*

Commission Discussion

The Commission finds and concludes it is just and reasonable in light of all the evidence presented that the appropriate amortization period for the deferred expenses for the Grid Improvement Plan costs is 17 years; the deferral shall include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period; that the deferral will include depreciation, property taxes, and returns through March 2023; the continuation of the deferred accounting treatment for Grid Improvement Plan investments until the rates effective date in the Company's next general rate case is approved; that Construction Work In Progress for Grid Improvement Plan investments will not be included in rate base in this case; and that Docket No. 2022-281-E is consolidated with this docket and resolved through this Settlement Agreement. The Commission further finds that the terms of the Settlement Agreement as laid out in Section B Paragraph 24(e) and (f) are also just and reasonable in light of the evidence presented and are therefore approved.

DEP Adjustment #27: SC5140 – Amortize deferred S.C. Act No. 62 Costs

Pursuant to Section 15 of Act 62, DEP recorded expenses incurred to implement Act 62 in a regulatory asset account. Tr. 768.30:18-19; Tr. 768.31:1-2. In its pro forma adjustment, the Company proposed to amortize the regulatory asset balance over a three-year period and included the balance, net of one year of amortization and taxes, in rate base for a revenue requirement impact of $0.7 million. Tr. 768.31:6-9. In her Supplemental Direct Testimony, Company Witness Elliott updated the adjustment to reflect the actual costs incurred from June 1, 2022, through August 31, 2022. Tr. 770.8:11-13. Witness Elliott testified that the Company did not include Act 62 costs beyond the capital cut-off in this case because the balance consists of costs that were not known and measurable. Tr. 774.20:3-4.

Witness Briseno testified that the ORS removed approximately $13,000 from the regulatory asset balance per the Company's response to discovery issued by ORS, an adjustment which the Company did not dispute. Tr. 774.6:13-17; 1012.21:1-3. ORS accepted the Company's proposed amortization period of three years for Act 62 costs but removed the end of the Test Year balance of Act 62 costs from working capital in rate base and did not include the unamortized balance in rate base. Tr. 1012.21:4-7. The Company opposes these adjustments for the reasons previously discussed.

As part of the Settlement Agreement, the Settling Parties agreed that the Act 62 expense deferral would not receive rate base treatment during the amortization period and will not include returns during the deferral period, and that the Act 62 regulatory asset should be amortized over a period of three years. Settlement Agreement Paragraphs 25(b) and 25(c).

Commission Discussion

The Commission finds these terms of the Settlement Agreement are a fair and reasonable resolution of this issue.

DEP Adjustment #21: SC5020 – Amortize rate case costs

In its Application in this case, the Company proposed to amortize over a five-year period the incremental rate case expenses incurred through May 31, 2022, and projected to be incurred for this docket, as well as costs incurred after the cut-off in the Company's last general rate case which have not been brought forth for recovery. Tr. 768.25:22-768.26:2. In Supplemental Direct Testimony, Company Witness Elliott updated the adjustment to reflect actual rate case costs from June 1, 2022, through August 1, 2022, and noted this update did not impact the total costs projected to be incurred and proposed for recovery in this rate case from what was filed in the Company's September 1, 2022 filing. Tr. 770.7:2-6.

ORS Witness Rabon proposed that the Commission limit the recovery of rate case expenses to the incurred, verified and allowable rate case expenses calculated to be

$3,414,000 as of the August 31, 2022 cut-off, to be amortized over five years and exclude the unamortized balance from rate base. Tr. 1034.6:7-11. Company Witness Elliott responded in Rebuttal Testimony, that if the Commission accepts the ORS proposal, the Company be permitted to continue to update the amount included with actual expenses through the hearing in this proceeding and include any costs not included for recovery in this case in a regulatory asset until recovery can be sought in the Company's next rate case. Tr. 774.20:11-16. Witness Elliott also noted that the Company had updated the adjustment for rate case expense to reflect corrections that needed to be made to the actual rate case expenses as of August 31, 2022, identified during the discovery process. Tr. 774.7:13-16. As part of the Settlement Agreement, the Settling Parties agreed that the rate case expense deferral would not receive rate base treatment during the amortization period and will not include returns during the deferral period, and that the rate case expense regulatory asset should be amortized over a period of five years. Settlement Agreement Paragraph 25(b) and 25(c). Additionally, the Settling Parties agreed that the rate case expenses requested in this case (which include the 2018 rate case expenses not previously recovered) are limited to actual and prudent expenses verified by the ORS not to exceed $4,500,000. Settlement Agreement at Section B Paragraph 26.

Commission Discussion

The Commission finds these terms of the Settlement Agreement are a fair and reasonable resolution of this issue.

DEP Adjustment #25: SC5100 – Amortize deferred SC AMI Costs

In Docket No. 2018-205-E, the Company petitioned for approval to record to a regulatory asset incremental O&M and depreciation expense incurred once the AMI technology meters were installed, as well as the associated carrying costs on the investment and on the regulatory asset at its WACC, which the Commission approved. Tr. 768.28:17-23. In the Company's last general rate case in Docket No. 2018-318-E, the Company requested approval to continue regulatory asset treatment for the incremental O&M and depreciation expense associated with ongoing AMI deployment,[21] including the carrying cost on the investment and on the regulatory asset balance at the WACC, approved in the case. Tr. 768.28:23—768.29:4. The Commission approved the Company's request for the continuation of the AMI regulatory asset with carrying costs on the capital-related costs only. Tr. 768.29:4-6. In its Application in this case, the Company made a pro forma adjustment to amortize the South Carolina AMI regulatory asset balance over a three-year period, and included the cost of capital portion of the balance, net of one-year of amortization and taxes, in rate base. *Id.* In her Supplemental Direct Testimony, Company Witness Elliott testified that the Company had updated the AMI deferred costs adjustment to reflect the actual South Carolina Advanced Metering Infrastructure plant additions through August 31, 2022. Tr. 770.8:3-5.

In his filed Direct Testimony, ORS Witness Briseno proposed an adjustment to the AMI deferral to remove all deferred equity returns included by the Company in the

[21] DEP completed its AMI deployment in January 2020. Tr. 842.27:3. Pursuant to Order No. 2019-341, the Company has provided annual reports on the AMI deployment and associated quantifiable customer savings. In DEP Witness Guyton's Testimony, he testified that these reports have served their purpose and there is no compelling reason to continue to submit them since AMI installation. *Id.* at 28. Therefore, the Company requested that the Commission stop the annual reporting requirement. *Id.* The Commission agrees that given the completion of the deployment, these reports are no longer needed and DEP is no longer required to make these annual filings.

deferral balance, utilize a cut-off of the deferral balance as of August 2022, calculate the deferred return using the Company's previously approved cost of debt, and utilize the 15-year amortization period recommended by ORS Witness Sandonato. Tr. 1012.19:12-16. The Company opposes these adjustments for the reasons previously discussed.

As part of the Settlement Agreement, the Settling Parties agreed that the AMI deferral will include a debt only return (at the most recent Commission approved debt rate) for the deferral period, and rate base treatment during the amortization period, and that the deferral will include depreciation and return on the known investment balance through March 2023. Settlement Agreement at Section B Paragraph 25(a). Further, the Settling Parties agreed that the AMI deferral should be amortized over a period of fifteen years. Settlement Agreement at Section B Paragraph 25(c).

Commission Discussion

The Commission finds these terms of the Settlement Agreement are a fair and reasonable resolution of this issue.

DEP Adjustment # 18: SC3090 – Amortize Roxboro Wastewater Treatment Plant costs

In its Application, the Company made an accounting request related to the Roxboro Wastewater Treatment plant. Application, p. 20. In her Direct Testimony, Company Witness Elliott further explained that the Company's Roxboro Wastewater Treatment Plant was retired early, and that the net book value of the plant was not fully recovered at the time of the retirement. Therefore, the Company requested approval to reclassify its net book value to an unrecovered plant regulatory asset account. The Company also requested approval to add to the regulatory asset dismantlement or other related costs incurred, net of salvage, related to the retirement. As detailed in pro forma Adjustment No. SC3090, the Company requested authorization to amortize the remaining unrecovered plant regulatory asset balance over five years and include the balance in rate base until it is fully recovered. Tr. 768.22:4-13.

In his Direct Testimony, ORS Witness Bickley testified that DEP proposed an adjustment of $160,000 for the total revenue requirement impact during the Test Year for the Roxboro Wastewater Treatment Plant. Tr. 1022.9:11-16. He also testified that the Company included $1,000,000 in estimates for dismantlement costs, but that there had been no dismantlement costs incurred by the Company to date. Tr. 1022.11:18-1022.12:3. He stated that ORS recommends disallowance of the $1,000,000 in dismantlement costs as the costs are not known and measurable and are estimates of potential future costs. He further testified that ORS recommends an amortization period of 11 years for the regulatory asset and for the early retired Roxboro Wastewater Treatment Plant to be excluded from rate base. Tr. 1022.12:6-10.

In Rebuttal, Company Witness Elliott explained that dismantlement costs of $1,000,000 on a system basis (approximately $90,000 on a South Carolina retail basis) are expected to be incurred for the decommissioning and demolition of the Roxboro Wastewater Treatment Plant bioreactor and associated land restoration costs resulting from the demolition as noted in Company Witness Julie Turner's Rebuttal Testimony. Tr. 774.16:3-7). She further acknowledged that its South Carolina retail amount of the dismantlement costs of approximately $90,000 is an estimate. However, she testified that this amount would be trued up in the regulatory asset balance to reflect the actual dismantlement costs to ensure that only the actual costs incurred are applied against the cost of removal reserve fund and that the difference is applied to reduce the regulatory asset balance to be recovered from customers. Tr. 774.16:18-774.17:1. She testified that if the Commission were to accept the ORS's proposed disallowance, the Company would respectfully request permission to add the actual incurred dismantlement costs to the regulatory asset balance once those costs have been incurred so they can be properly applied against the cost of removal funds the Company has already collected to cover those costs. Tr. 774.17:4-8. She concluded by stating that this Commission and other state utility commission had approved rate base treatment for unrecovered plant in the past. Tr. 774.17:9-774.18:19.

In her Rebuttal, Company Witness Turner testified that the Roxboro Wastewater Treatment Plant had to be replaced to meet state and federal environmental requirements, and that the Roxboro Wastewater Treatment Plant was a prudent investment. Tr. 888.13:16—888.15:18. She further testified that no one could have reasonably expected the early retirement. *Id.* In Surrebuttal, ORS Witness Briseno stated that should the Commission disagree with ORS's recommendation and include the Roxboro Wastewater Treatment Plant regulatory asset in rate base as proposed by the Company, ORS recommends that the balance included in working capital reflect the removal of the first year of amortization expense. Tr. 1048.12:12-18.

Section B, Paragraph 27 of the Settlement Agreement provides that the Parties agree to the ORS's recommendation to exclude the Roxboro Wastewater Treatment Facility from rate base, extend the amortization period to 11 years, and remove the estimated dismantlement costs from the calculation of the amortization expense. Further, the Settlement Agreement provides that DEP may charge actual dismantlement costs to the regulatory asset and continue the amortization until the regulatory asset is fully amortized, provided the ORS may review the actual dismantlement costs for reasonableness and prudence in the Company's next rate case. Company Witness Callahan and ORS Witness Hipp supported this provision through their testimony in support of the Settlement Agreement. Tr. 649.5:1-649.7:2; 983.2:16-8.

Commission Discussion

No other party offered any evidence addressing this issue. The Commission finds and concludes it is just and reasonable in light of all the evidence presented, for purposes of this proceeding, that the Company exclude the Roxboro Wastewater Treatment Facility from rate base, extend the amortization period to 11 years and to remove the estimated dismantlement costs from the calculation of the amortization expense. The Commission further finds and concludes it is just and reasonable in light of the evidence presented, for purposes of this proceeding, that DEP be authorized to charge actual dismantlement costs to the regulatory asset and continue the amortization until the regulatory asset is fully amortized, provided the ORS may review the actual dismantlement costs for reasonableness and prudence in the Company's next rate case.

Depreciation Rates

The evidence supporting Section B Paragraph 29 of the Settlement Agreement is contained in the testimony and exhibits of DEP Witnesses Spanos, Elliot, and Speros; ORS Witnesses Garrett and Seaman-Huynh; DoD/FEA Witness Andrews; and the entire record in this proceeding.

In his Direct Testimony and Exhibits, Company Witness Spanos supported the Company's 2018 Depreciation Study, the 2020 Nuclear Depreciation Study, and the 2021

Depreciation Study. Tr. 876.3:18-21; Hearing Exhibit No. 20. As explained by DEP Witness Speros, the Company's rate request in this case was based upon the 2018 Depreciation Study adopted and amended by the North Carolina Utilities Commission (NCUC) in Docket No. E-2, Sub 1219. Tr. 880.8:1—880.9:8; Hearing Exhibit No. 20, pp. 1333-1340. For nuclear plants, DEP's request in this case is based upon the depreciation rates in the 2020 Nuclear Depreciation Study. Tr. 880.8:1-6; Tr. 876.4:17-20; Hearing Exhibit No. 20, pp. 1341-1465. Additionally, through the Testimony of Witnesses Spanos and Elliott, DEP requested that the incremental increase in depreciation expense resulting from the 2021 Depreciation Study be deferred. Tr. 876.4:3-7; 768.43:10-20.

Witness Spanos' Direct Testimony further explained that the 2021 Depreciation Study provided the most current annual depreciation accruals related to electric plant in service for ratemaking purposes as well as the appropriate average service life and net salvage percentages for each plant account. Tr. 876.5:17-20. In performing the study, Witness Spanos utilized the straight-line remaining life method of depreciation with the average service life procedure for all plant assets with the exception of general plant accounts. Tr. 876.7:1-4. The 2021 Study was performed in a manner consistent with prior DEP depreciation studies filed with the Commission. Tr. 876.24:6-12.

In his filed Direct Testimony, ORS Witness Garrett recommended the Commission use and approve the 2021 Depreciation Study with his recommended changes, arguing that using rates from the 2018 Depreciation Study is obsolete and should not be the basis of the Company's depreciation rates. Tr. 1040.7:2-3. Witness Garrett and ORS Witness Seaman-Huynh testified that the Mayo Unit 1, Roxboro Units 3 and 4, and Roxboro Common facilities retirement dates should not be updated while the retirement dates are pending in proceedings before the NCUC. Tr. 1040.14:10-14; 1030.7: 7:1-11. In his Direct Testimony, ORS Witness Seaman-Huynh argued that there is "uncertainty on the actual retirement dates" for the Roxboro facilities and that the retirement dates are subject to change. Tr. 1030.7:1-15. He testified that ORS disagrees with the Company's proposal to accelerate the depreciation of the Roxboro Wastewater Treatment plant and recommends the facility continue to be depreciated over its current remaining life spans. *Id.*

ORS Witness Garrett's Testimony recommended the Commission remove the Company's added 2.5% escalation factor for demolition and decommissioning costs and the 10% contingency factor included in the decommissioning study. Tr. 1040.16:4-12; Tr. 1040.17:3-5; Tr. 1040.18:18-20. Witness Garrett's Testimony proposed reduced depreciation rates for several mass property accounts: 352 (Structures and Improvements), 356 (Transmission Overhead Conductors and Devices), 364 (Poles, Towers and Fixtures), 365 (Distribution Overhead Conductors and Devices), 368 (Line Transformers), and 369 (Services). Witness Garrett based his reduced deprecation rates on the selection of Iowa Curves that he argued better fit the Company's data. Tr. 1040.24:8-10; 1040.27:1-4; 1040.29:6–1040.30:2; 1040.30:6-8; 1040.34:6-8; 1040.37:6-10.

Witness Andrews testified on behalf of the DoD/FEA and recommended adjustments to specified transmission and distribution plant accounts in the 2021 Depreciation Study. Tr. 910.3: 5-13. Witness Andrews also recommended lengthening the average service lives for accounts 355 (Poles and Fixtures), 356 (Transmission Overhead Conductors and Devices), 362 (Station Equipment), 364 (Poles, Towers and Fixtures), 365 (Distribution Overhead Conductors and Devices), 368 (Line

Transformers), 369 (Services), and 371 (Installations). Tr. 910.16; Table 3; Hearing Exhibit No. 32. Witness Andrews testified that for each of the proposed adjustments, his survivor curve better fit the Company's data. Tr. 910.16: 1-7. Witness Andrews also recommended the Company adjust its net salvage rates based on the Company's historical retirement data from 1979-2021 for accounts 353, 361, 362, 364, 365, and 371. Tr. 910.23: 14-910.24:3. Witness Andrews testified that the updated life span estimates for Mayo and Roxboro were reasonable. Tr. 910.14: 17-20.

In his Rebuttal Testimony, DEP Witness Spanos responded to ORS and DoD/FEA's adjustments and recommendations to certain service life and net salvage accounts. Tr. 878.2: 12-17. Witness Spanos summarized the mass property adjustments proposed by the Parties in his Testimony, and he explained his methodology for calculating the average service lives and net salvage rates in comparison. Tr. 878.14:1-878.15:9. Witness Spanos cautioned against overreliance on mathematical only solutions and emphasized the importance of using informed judgement in calculating the appropriate depreciation rates. Tr. 878.16:3--878.17:7; 878.19:29--878.20:3. He further explained the reasons for the differences between his proposed depreciation rates and the adjustments recommended by ORS Witness Garrett and DoD/FEA Witness Andrews. Tr. 878.19:29--878.20:22.

Witness Spanos' Rebuttal Testimony also responded to ORS's proposal to use the previous retirement dates for Mayo Unit 1 and Roxboro Units 3 and 4, testifying that the updated retirement dates were not "accelerated" as suggested by Witness Garrett, but instead are consistent with the shorter life spans for coal-fired power plants being experienced across the industry. Tr. 878.5:1-15. Witness Spanos also testified that contingency costs are a standard component of decommissioning studies that are already imbedded in depreciation rates; therefore, removing contingency costs would create an intergenerational inequity. Tr. 878.13:4-13.

ORS Witness Seaman-Huynh testified in his Surrebuttal that the retirement dates for Mayo Unit 1 and Roxboro Units 3 and 4 are speculative due to the Company's anticipated 2023 Integrated Resource Plan filing and should not be changed. Tr. 1060.5: 3-11. In his Surrebuttal Testimony, ORS Witness Garrett testified, consistent with his Direct Testimony, that contingency costs should not be included in rates. Tr. 1068.4: 9-16. Witness Garrett further testified that his service life estimates applied the appropriate relevant factors. Witness Garrett disagreed with DEP Witness Spanos' Testimony that removing contingency costs would create intergenerational inequity, and he disputed the Company's claim that he relied exclusively upon mathematical solutions when estimating service lives. Tr.1068.5: 10-18. In his Surrebuttal Testimony, DoD/FEA Witness Andrews explained that his service life and net salvage rate adjustments were reasonable and in line with widely accepted depreciation methods, and that his net salvage adjustments were in line with the Company's historical net salvage rate averages. Tr. 912.4: 8-16; 912.6: 1-7.

Section B Paragraph 29 of the Settlement Agreement provides that the 2021 Depreciation Study be accepted for ratemaking purposes and that DEP shall not establish a regulatory asset to record the 2021 Depreciation Study's incremental impact. The Settlement Agreement also provides the Company accept the ORS recommended adjustments to the 2021 Depreciation Study for Accounts 364, 365, 368, and 369, accept the retirement date of 2033 for the Roxboro common facilities, and remove the escalation rate of 2.5%. In turn, the Settlement Agreement provides the ORS accept the Company's adjustments to the 2021 Depreciation Study for Accounts 352 and 356, Mayo Unit 1, Roxboro Units 3 and 4, and contingency.

Commission Discussion

No other party offered any evidence addressing these issues. The Commission finds and concludes Section B Paragraph 29 of the Settlement Agreement to be just and reasonable in light of all the evidence presented.

Storm Costs and Storm Reserve Fund

As reflected in Witness Elliott's Direct Testimony Exhibits (Hearing Exhibit No. 10, pp. 1-243), and noted by ORS Witness Bickley, the Company proposed to normalize storm restoration costs using a five-year range (2017-2021) of storm costs, removing the highest and lowest storm years, and including the average of the remaining three years to determine the adjustment. Tr. 1022.22: 1-7. Hearing Exhibit No. 4, p. 283.

In addressing the normalization of storm costs, Witness Bickley's Direct Testimony presented ORS's recommendation that storm costs be normalized using a ten-year time period (2012-2021), removing the highest and lowest values, resulting in an average of the remaining eight years. Tr. 1022.23:1-19. ORS's recommendation removed storm costs identified by the Company as those which would be sought for recovery through the Storm Securitization Docket (Docket No. 2022-256-E) *Id.*

In her Rebuttal Testimony, DEP Witness Elliott points to the increases in costs for contract labor over the last ten years, and interpreted ORS's Testimony as implying that the Company should be able to hire contract workers for the same hourly rate in 2022 as it did in 2012 and, for that reason, the Commission should reject ORS's recommendation.

Tr. 774.26:9-21. She also noted that the methodology proposed by the Company was the same as included in the Stipulation between ORS and the Company adopted by the Commission in Order No. 2019-341. Tr. 774.25: 19-774.26:1.

In his Surrebuttal Testimony, ORS Witness Bickley stated that ORS's recommendation was based on the Company's actual and observed historical costs to establish a normalized level of storm costs that appropriately reflects future levels of costs for the Company. Tr. 1054.14:19-21. Moreover, the Stipulation as adopted as part of Order No. 2019-341 is not precedential for the purposes of subsequent rate cases, nor did it serve as sufficient justification to continue using that methodology in the instant proceeding. Tr. 1054.14:22-1054.15:1.

In his Direct Testimony, DEP Witness Bickley stated that the Company proposed to establish a Storm Reserve that includes $3,000,000 in annual collections per year from customers with a year of collections net of accumulated deferred income taxes to be included within rate base as a regulatory liability, as well as a Storm Reserve Limit of $50,000,000. Tr. 1022.24:1-5.

ORS Witness Bickley noted in his Direct Testimony that ORS, upon reviewing the Company's proposal, did not object to the establishment of a Storm Reserve that contained sufficient customer protections, supported continued service reliability, and contained reasonable guidelines for how the Storm Reserve was managed by the Company. Tr. 1022.28:18-20. Witness Bickley outlined six consumer protection recommendations that the Storm Reserve proposed by the Company should include. Tr. 1022.29:4--1022.30:19.

Section B Paragraph 30 of the Settlement Agreement provides that the Settling

Parties accept the Company's proposal to normalize storm costs over a five-year period. The Settlement Agreement also provides, at Section B Paragraph 31, that the Settling Parties agree to accept the Company's recommendation to establish a storm reserve to collect $3,000,000 per year, with an accumulated reserve not to exceed $50,000,000, subject to the customer protections recommended by ORS.

Commission Discussion

No other party offered any evidence addressing this issue. The Commission finds and concludes that the normalization of storm costs over a five-year period as established in Section B Paragraph 30 of the Settlement Agreement, and the establishment of a Storm Reserve Fund, subject to the customer protections as described in ORS Witness Bickley's Testimony and Section B Paragraph 31 of Settlement Agreement, to be just, reasonable, and in the public interest in light of all the evidence presented, for purposes of this proceeding.

Nuclear Materials and Supply Inventory

In his Direct Testimony, ORS Witness Thompson argued that nuclear materials and supplies (M&S) inventory that have had repair hold, quality hold, quality pending, and stores hold classifications for over four years cannot be used and recommended that the cost of this M&S inventory be excluded from recovery. Tr. 1026.6:5 – 1026.9:22.

In his Rebuttal Testimony, Company Witness Ray testified that this inventory is held to support plant operations and is therefore of benefit to customers. Witness Ray explained that while, in general, inventory is held in a state that supports immediate issue and use, many spare parts that are required to support nuclear operations have significant lead times. He noted that while many of these spare parts are not frequently required, sufficient inventory can often be a determining factor in the Company's ability to keep the nuclear units on-line and producing to their maximum capacity, and in other cases helps ensure outages are executed as safely and efficiently as possible to minimize offline time. He concluded that it is incorrect to assume that simply because an item is on hold longer than four years such inventory will not ultimately be used or available for use, when needed; rather, the inventory can be made available should priorities dictate applying the maintenance or engineering attention to the cause for the hold. Tr. 864.3:7-13; 864.5:3-18; 864.11:1-4.

In his Surrebuttal Testimony, ORS Witness Thompson acknowledged the Company's obligation to provide high-quality and reliable service to its customers but contended that the inclusion of nuclear M&S Inventory purchased prior to 2018, and therefore not used and useful to provide service, imposes an unnecessary cost on customers. Witness Thompson suggested that a regular, periodic evaluation and review of on hold inventory to confirm the existence and availability of the M&S Inventory would be beneficial. He also recommended that the Company be required to have an independent third-party perform a review and audit of the DEP nuclear, fossil, and hydro M&S Inventory and program controls. He recommended that the independent audit of M&S Inventory shall be, at a minimum, for at least one nuclear, one fossil, and one hydro station by the time of the Company's next general rate case filing, or within three years of the Commission's order in this rate case, whichever is sooner. He also recommended that the Company should establish a long-term schedule for continuous independent audit cycle for M&S Inventory (e.g., a three-to-five-year rotational cycle). Tr. 1056.2:1-1056.4:16.

The Settlement Agreement provides that the Parties accept the Company's position that no exclusions should apply to M&S Inventory. The Parties also accept that the Company is required to have an independent third-party perform a review and audit of the DEP nuclear, fossil, and hydro M&S inventory and program controls. The independent audit of M&S inventory shall be, at a minimum, for at least one nuclear, one fossil and one hydro station by the time of the next general rate case filing, or within three years of the Commission order in this rate case, whichever is sooner. The Company shall establish a long-term schedule for continuous independent audit cycles for M&S inventory (e.g., a three- to five-year rotational cycle). Tr. 1056.3:16-1056.4:5. Witness Callahan and ORS Witness Hipp supported this provision through their Testimony in support of the Settlement Agreement. Tr. 649.5:6-9; Tr. 981.2:14-981.5:8.

Commission Discussion

No other party offered any evidence addressing this issue. The Commission finds and concludes it is just and reasonable in light of all the evidence presented, for purposes of this proceeding, that no exclusions should apply to M&S Inventory and that the Company should have an independent third-party perform a review and audit of the DEP M&S inventory and program controls as described in ORS Witness Thompson's Testimony and the Settlement Agreement.

Plant Held for Future Use

In its Application, the Company included $5,268,000 in Plant Held for Future Use (PHFU) in rate base on a South Carolina retail basis. Hearing Exhibit 10, p. 4 (Elliott Direct Exhibit No. 1, p. 4). In his Direct Testimony, ORS Witness Omari R. Thompson recommended removing all PHFU not used within the last four years, as it is not considered used and useful. Tr. 1026.9:1-2. Consistent with this position, ORS proposed to adjust the PHFU balance by ($3,429,000). *Id.* As explained in the Direct Testimony of ORS Witness Courtney D. Radley, ORS also proposed to remove the corresponding property taxes on disallowed PHFU. Tr. 1014.12:16-23. On Rebuttal, Company Witness Brent C. Guyton testified that the Company disagreed with the ORS' exclusion of these PHFU costs. Tr. 844.35:10-12. Witness Guyton explained that as a result of the Company's forward-looking siting and land purchase strategy, land is sometimes purchased and held for more than four years without being used. Tr. 844.35:13-844.37:6. Witness Guyton noted that this forward-looking strategy often saves customers money and allows the Company to minimize potential customer impacts. *Id.* For purposes of settlement, the Parties agreed that no exclusion should be applied to PHFU greater than four years Hearing Exhibit 6, Paragraph 16 (Settlement Agreement).

Commission Discussion

The Commission finds this is a reasonable resolution of this issue.

Rent Expense

ORS Witness Bickley recommended an adjustment to "remove the costs associated with office space and rent and lease for the 526 S. Church Street and 550 S. Tryon Street locations from the Test Year." Tr. 1022.34:12-14. In support of this recommendation, ORS Witness Bickley explained that these expenses should not be included for ratemaking purposes because neither property is occupied or owned by the Company. Tr. 1022.34:16-18. Company Witness Elliott explained that inclusion of those costs is appropriate because the Company "will continue to incur its allocated share for rent and lease costs for office space for its employees in Charlotte." Tr. 774.27:9-11.

Company Witness Elliott noted that going forward, the "rent expense allocation will now be for the new Duke Energy Plaza building instead of 526 South Church Street and 550 South Tryon. Tr. 774.28:2-3. As such, Company Witness Elliott explained that the ORS's recommendation is unreasonable because it fails to account for the additional rent and lease costs for the new Duke Energy Plaza Building. Tr. 774.28:5-10. In response, ORS Witness Bickley testified that ORS's adjustment to rent expense did not remove properties that would be utilized by the Company after the rates in this proceeding become effective. Tr. 1054.15:13-15.

Section B, Paragraph 34 of the Settlement Agreement stipulates that no adjustment will be made to the Company's Test Year Facilities Rent expense. All Parties support this position and the Company will continue to incur rent and lease expenses once relocated to the new Duke Energy Plaza building.

Commission Discussion

After consideration of the evidence in the record, the Commission concludes that the Company's proposed Test Year Facilities Rent Expense is just and reasonable and approves the same.

Non-allowables

The Company, through Company Adjustment SC2080, proposed to adjust other O&M expenses by ($2,386,000) and income taxes by $595,000 to remove COVID-19 deferral expenses, consultant expenses, and "provide an allowance for mischarges as a result of human error in coding Company expenses as well as other agreed upon non-allowable adjustments." Tr. 1034.5: 3-6. ORS, through Witness Rabon, noted that "ORS reviewed expenses for potential non-allowable items not previously identified by the

Company and accepts the Company's adjustment as proposed." Tr. 1034.5: 7-8.

As a condition of, and consideration for, the resolution reached in the Settlement Agreement, the Parties agreed in Section B, Paragraph 35 to include $19,990 of expenses disallowed in Docket No. 2022-255-E.[22] This amount will be applied to Adjust Test Year Expenses (Non-Allowables) adjustment (ORS Adjustment 9 and Company Adjustment SC2080). All Parties support this position and this amount represents a reasonable compromise by the Parties when considered against the comprehensive resolution this concession helped, in part, to achieve.

Commission Discussion

After consideration of the evidence in the record, the Commission concludes that the application of $19,990 of expenses disallowed in Docket No. 2022-255-E to the Adjust Test Year Expenses adjustment is just and reasonable and approves the same.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-34

Cost of Service Study

The evidence supporting these findings of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of Company Witness Hager; ORS Witness Watkins; SCEUC Witness O'Donnell; Walmart Witness Perry; DCA Witness Dismukes; Nucor Steel Witness Pollock; DoD/FEA Witness Gorman, and the entire record in this proceeding.

[22] *Amended Order Approving Rider DSM/EE-14,* Order No. 2022-855(A), Docket No. 2022-255-E (Jan. 13, 2023).

Summary of the Evidence

In her Direct Testimony, Company Witness Hager explained that the purpose of the cost of service study is to align the total costs incurred by Company in the test period with the jurisdictions and customer classes responsible for the costs. Tr. 846.5:10-12. Company Witness Hager noted that the Company's cost of service study directly assigns or allocates the Company's revenues, expenses, and rate base among the regulatory jurisdictions and customer classes served by the Company. Tr. 846.5:12-14. She testified that the allocations are based on the service requirements of each respective jurisdictions and customer classes. Tr. 846.5:14-15. Company Witness Hager noted that cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Tr. 846.5:17-19.

Company Witness Hager reviewed the Company's cost of service study and stated that it is based on the official accounting books and records of the Company. Tr. 846.6:19-20. Company Witness Hager described the cost of service study as containing "three key activities . . . when assigning costs." Tr. 846.7:5. She explained that the Company first grouped costs according to their function, which include "production (generation), transmission, distribution, and customer service, billing, and sales." Tr. 846.7:7-9. Company Witness Hager noted that after costs are "functionalized," they are grouped based on the utility "operation" or service being provided and the related causation of the costs. Tr. 846.7:10-12. Finally, after the costs have been functionalized and classified, Company Witness Hager testified that they "are allocated or directly assigned to the proper jurisdiction and customer class based on the manner in which costs are incurred." Tr. 846.7:14-16.

In this case, Company Witness Hager stated that the Company used two primary demand allocators to allocate those costs. Tr. 846.10:14. Production and Transmission Costs were allocated using the "Twelve Coincident Peak (12 CP) method." Tr. 846.10:16-18). Distribution plant investments were "directly assigned to the jurisdictions." Tr. 846.10:19-20.

Company Witness Hager provided various reasons why the use of the 12 CP is appropriate, which included alignment with the Company's IRP, rate stability across test periods, mitigation of weather effects that impact a single coincident peak, and conformance with precedent across the country (both at the FERC and at state commissions). Tr. 846.12:14-846.13:3.

Overall, Company Witness Hager testified that the Company's cost of service study provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. Tr. 846.26:19-21.

ORS Witness Watkins examined the Company's cost studies and determined them to "be mathematically accurate" and replicable. Tr. 1010.9:2-4. With respect to the allocation factors specifically, ORS Witness Watkins first examined the Company's utilization of the 12 CP. Tr. 1010.28:13-15. ORS Witness Watkins explained that use of the 12 CP "strikes a reasonable balance" between cost allocation philosophies. Tr. 1010.31:5-7. With respect to the Company's classification of distribution plant between customer and demand, ORS Witness Watkins explained that this is a reasonable result given the "geography and demographics of DEP's service area." Tr. 1010.34:1-3. In addition, ORS Witness Watkins agreed with Company Witness Hager that utilization of the Non-Coincident Peak for demand-related costs is appropriate and opined that it is an "accepted industry approach." Tr. 1010:34:11-12. Finally, ORS Witness Watkins noted that the Company's proposed class-based rate revenue increases are generally reasonable, with certain limited exceptions. Tr. 1010.5:3-5.

DoD/FEA Witness Gorman objected to DEP's switch to a 12 CP method. Tr. 918.23:13-17. Nonetheless, DoD/FEA Witness Gorman noted he would not take issue with the Company's revised allocation and transmission capacity costs using the 12 CP methodology, but he recommended the Commission use a 12 CP methodology "in prospective rate cases" to allocate production and transmission capacity costs across rate classes. Tr. 918.24:5-11.

In his Direct Testimony, SCEUC Witness O'Donnell objected to DEP's change in the cost of service methodology. Tr. 894.8:4-5. SCEUC Witness O'Donnell recommended the use of "FACOS models with the generation investment based on single-CP and 2-CP." Tr. 894.14:5-8.

Nucor Steel Witness Pollock noted that, with one exception, DEP's cost of service study comports with accepted industry practice and that it "recognizes the different types of costs it incurs, as well as the different ways electricity is delivered to, and used by, its various types of customers." Tr. 924.7:11-16. However, Nucor Steel Witness Pollock raised issues with DEP's 12 CP method, noting "[the] equal weighting fails to recognize that DEP has pronounced seasonal peaks, and it dilutes the effect of the actual peak months." Tr. 924.19:1-3. Thus, Nucor Witness Pollock recommended that if the Commission wishes to change DEP's current 1 CP allocation methodology, a 2 CP or 4 CP approach would be a "reasonable compromise" between maintaining the current single coincident peak methodology and switching to 12 CP as the Company proposes.

Tr. 924.20:14-17.

Walmart Witness Perry noted that production plant costs should be allocated on a "multiple CP basis at ten percent of maximum system peak." Tr. 968.21:7-8. Walmart Witness Perry recommended the Commission approve a 4 CP production cost allocation methodology for the Company's fixed production plant costs "based on the system's four highest peak months as shown in the Company's test year data." Tr. 968.23:10-15. Walmart Witness Perry opined that a 4 CP method would help "ensure rate stability," "mitigate the weather effects that impact a single coincident peak," and "ha[ve] the added benefit of being consistent with the concept of gradualism." Tr. 970.6:13-17.

DCA Witness Dismukes disagreed with the Company's cost of service study cost allocation method related to the classification of production plant. Tr. 898.17:3-6. DCA Witness Dismukes opined that the Company's cost allocation method placed too much emphasis on class peak contribution relative to annual energy use. Tr. 898.17:6-8. DCA Witness Dismukes recommended the Company adopt an Average & Peak 12 CP cost allocation method for costs associated with the Company's production plant assets. Tr. 898.24:14-15; Tr. 898.30:20-22. Further, DCA Witness Dismukes recommended that the Company classify all distribution plant assets included in FERC Accounts 364 through 368 as 100 percent demand related. Tr. 898.30:13-15.

Section B Paragraph 38(b) of the Settlement Agreement, which settled the contested issues between the Parties in this case, establishes the Parties' agreement that the increase in revenue agreed upon in this proceeding will be allocated to each rate class consistent with the cost of service study discussed by Witness Hager with proforma adjustments necessary to reflect the provisions of the Settlement Agreement.

Commission Discussion

The Commission finds Section B, Paragraph 38(b) of the Settlement Agreement is just and reasonable in light of all the evidence presented that the Company regarding allocations to each rate class consistent with the testimony of Company witness Hager. The revenue allocation agreed upon by the Parties in the Settlement Agreement filed in this docket on January 12, 2023 is approved. Settlement Agreement, pp. 17-18, ¶ 38.b. The cost of service study adopted by the Parties for the purpose of the Settlement Agreement, and the revenue allocation, shall not have any precedential effect in future proceedings and all Parties may argue for different cost allocation, rate design, and revenue spread methodologies in future cases.

Rate Design

The evidence supporting these findings of fact is found in the verified Application; the Settlement Agreement; the testimony and exhibits of Company Witnesses Reed and Byrd; ORS Witness Watkins; DoD/FEA Witness Gorman; DCA Witness Dismukes; SCEUC Witness O'Donnell; Walmart Witness Perry, and the entire record in this proceeding.

Summary of the Evidence

In her Direct Testimony, Witness Reed explained that she used the cost of service information prepared by the Company and examined by Company Witness Hager to design rates. Tr. 780.11:5-6. Company Witness Reed also leveraged and considered the rates of return across the customer classes derived from the cost of service study when designing rates. Tr. 780.11:9-10. Finally, Company Witness Reed noted that she reviewed the Company's Advanced Metering Infrastructure ("AMI" or Smart Meter) data to examine customers' usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of the Company's rates including the development of new time-of-use periods. Tr. 780.11:11-16.

Company Witness Reed explained that one objective of the Company's proposed rate design is to achieve the necessary increase in rates to collect the total revenue requirement. Tr. 780.12:9-11. In doing so, Company Witness Reed stated that the Company's goal is to gradually align the cost to serve customers within its residential, general service, and lighting rate schedules. Tr. 780.12:11-13. Company Witness Reed also noted that rates should be designed in a way that reflects the costs a customer causes the Company to incur. Tr. 780.12:11-13.

With respect to the rate increases proposed in this case, Company Witness Reed stated that the base rate increase has been allocated to the rate classes by rate base amounts. Tr. 780.14:5-6. Company Witness Reed explained that this allocation methodology distributes the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. Tr. 780.14:6-8.

Company Witness Reed testified that the Company is also recommending a variance reduction of 10% to help reduce interclass subsidies to better align each rate class to the average rate of return. Tr. 780.14:8-10. Additionally, the Company analyzed rate migration in the rate design process. Tr. 780.14:22 – 780.15:1. In her Direct Testimony, Company Witness Reed explained that rate migration occurs when customers migrate from their current tariff to another tariff to save money. Tr. 780.14:22-780.15:1. Witness Reed further stated that the Company's requested migration adjustment ensures that the Company recovers the full amount of the revenue requirement, which in turn protects other classes from absorbing these costs in future rate cases through interclass subsidies. Tr. 780.15:13-15. Company Witness Reed recommended a migration adjustment to the residential and medium general service rate classes for customers who would save 10% or more annually. Tr. 780.15:4-6. Company Witness Reed noted that, in total, this proposal would result in a $0.9 million migration adjustment for the residential class and $1.7 million migration adjustment for the medium general service class. Tr. 780.15:6-9. Company Witness Reed provided various supporting workpapers in the form of Exhibit 1 through Exhibit 8 of her Testimony (Hearing Exhibit No. 17, pp. 3-262). Tr. 780.6: 6- Tr. 780.7:21.

Company Witness Byrd testified that the Company participated in a year-long Comprehensive Rate Design Study with external stakeholders to develop the Company's future pricing and rate design options. Tr. 832.5:11-13. As a result of this engagement, the Company proposed several rate design changes to directly incorporate requests and input from stakeholders. Tr. 832.6:4-5. Company Witness Byrd further testified that in addition to the changes proposed in Company Witness Reed's Testimony, the Company is also proposing "a series of rate design changes to protect customers from cross-subsidizations, send price signals that encourage system benefits, and generally modernize the Company's pricing structure." Tr. 832.6:13-16.

Company Witness Byrd explained that these proposals include updated and aligned TOU periods across both residential and non-residential customers. Tr. 832.6:17-19. Company witness Byrd noted that consistent with those updates, the Company is also proposing changes to demand charge structures to align with the new periods. Tr.

832.6:19-21.

Taken together, Company Witness Byrd stated that these proposals improve price and cost-causation alignment, allow for "simplification elsewhere in the rate designs, and offer greater opportunity for load management activities to control customers' energy costs and create benefits for the broader system." Tr. 832.6:21-832.7:2.

In his Direct Testimony, ORS Witness Watkins "determined that Witness Reed's proposed class base rate revenue increases before her proposed rate migration adjustment are reasonable," with one exception related to the revenue increase to the Small General Service (SGS) class. Tr. 1010.38:1-3. With respect to the rate migration adjustment proposed by Company Witness Reed, ORS Witness Watkins disagreed noting that not all customers "that would save at least 10% on their base rate bill (excluding riders and fuel) would indeed switch rate schedules." Tr. 1010.41:19-20. Lastly, ORS Witness Watkins stated that the Company has not (and cannot) estimate those customers that do switch rate schedules but end up paying more in their base rate bill. Tr. 1010.42:2-3.

DoD/FEA Witness Gorman determined that "[a] 10% subsidy reduction does not result in cost-based rates and proposing new rate designs with this level of cross-subsidization is inappropriate." Tr. 918.26:30-31. DoD/FEA Witness Gorman suggested a 25% subsidy reduction "moves classes closer to cost of service than under the Company proposal, but limits increases to the Residential class to no more than 1.5x the system average increase." Tr. 918.26:6-8.

In his Direct Testimony, DCA Witness Dismukes challenged the Company's proposed changes to the Residential Time of Use-Demand (R-TOUD) rate because the rate design is "duplicative in intent [and] may very well lead to customer confusion." Tr.

898.42:6-8. DCA Witness Dismukes recommended the Company redesign the R-TOUD rate to only feature three time-variant energy charges in addition to a basic facilities charge. Tr. 898.45:11-13.

SCEUC Witness O'Donnell recommended the Company file a coincident peak rate that can be coupled with a renewable energy resource owned by the customer. Tr. 894.14: 16-17. SCEUC Witness O'Donnell suggested that a CP rate coupled with renewable energy resource would "help slow the peak growth of the DEP system while also flattening the load curve of the Company." Tr. 894.14:17-19.

In her Direct Testimony, Walmart Witness Perry did not take a position on the Company's proposed Time of Use (TOU) periods. Tr. 968.8:13-17. Walmart Witness Perry also did not oppose the Company's proposed structural rate design changes or proposed rate levels for Medium General Service – Time of Use (MGS-TOU). Tr. 968.8:18-23. Walmart Witness Perry noted, however, "to further align cost recovery from customers with the costs of service, if there is a decrease in revenue requirement, then such decrease should be applied proportionately to the energy charges to bring these charges closer to their cost of service-based levels." Tr. 968.33:16-19.

Section B, Paragraph 38(a) of the Settlement Agreement establishes all Parties' agreement with the rate design included in Attachment B through Attachment E of the Settlement Agreement, which allocates an increase in rates across classes. The compromise includes a 50% migration adjustment. As part of the compromise, Section B, Paragraph 38(c) also establishes the Parties' agreement that DEP will reduce Rate

Schedule LGS-TOU's[23] on-peak energy charges by the reduction in the revenue requirement, exclusive of any EDIT decrements, allocated to Rate Schedule LGS-TOU associated with the Settlement Agreement. That same paragraph also establishes the Parties' agreement that the proposed reduction to the EDIT Rider allocated to Rate Schedule LGS-TOU shall apply to the on-peak, off-peak, and discount energy periods.

In her settlement Testimony, Company Witness Reed explained that Attachment B through Attachment E of the Settlement Agreement (Hearing Exhibit No. 6, pp. 54–67) are updated exhibits to her Direct Testimony which have been modified to reflect the compromises in the Settlement Agreement. Tr. 784.3:21-784.4:3. Company Witness Reed stated that the rate design therein and Settlement Agreement (Hearing Exhibit No. 6) as a whole represent "a just and reasonable resolution of the issues in this proceeding." Tr. 784.5:21. With respect to Attachment B through Attachment E of the Settlement Agreement (Hearing Exhibit No. 6, pp. 54-67), Company Witness Reed explained that the rate design contained therein is consistent with ratemaking principles, "which seek equitable pricing structures and gradual alignment with the cost to serve our customers." Tr. 784.6:1-3.

Commission Discussion

After consideration of the evidence in the record, a review of Company Witness Reed's updated exhibits, and the evidence of record in this docket, the Commission agrees that Attachments B through E (Hearing Exhibit No. 6, pp. 54-67) represent just and reasonable rates and are based upon sound cost of service principles. Therefore, the

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[23] Large General Service – Time of Use.

rate design (including the 50% rate migration adjustment and modifications to Schedule LGS-TOU) contained in Attachment B through Attachment E of the Settlement Agreement is approved. Hearing Exhibit No. 6, pp. 54-67.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

(Lead/Lag Study)

The evidence supporting this finding of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of DEP Witness Elliott, ORS Witness Briseno, and the entire record in this proceeding.

In its Application, the Company proposed to adjust cash working capital by $4,103,000, updated to $4,078,000 in its Supplemental filing, for the impact of its accounting and pro forma adjustments utilizing the 1/8th (12.5%) of O&M expenses methodology.

For this case, ORS utilized the same 1/8th of O&M methodology but excluded the pro forma adjustment amount of uncollectibles ($322,000) from its calculation of the cash working capital adjustment Tr. 1012.22:10-14. In his Direct Testimony, ORS Witness Briseno stated that a rate base allowance for cash working capital is intended to compensate the utility for investor supplied funds used to finance the day-to-day cash operating needs of the utility. Tr. 1012.23:12-14. Cash flows arising from non-cash expenses, such as uncollectibles, do not serve this purpose and, therefore, should not be included in the cash working capital allowance Tr. 1012.23:15-20. For the same reasons, depreciation and deferred income taxes are excluded from the calculation of cash working capital when utilizing the 1/8th method *Id.*

ORS recommended that DEP be required to perform and present a lead-lag study in its next general rate proceeding Tr. 1012.22:13-14. In articulating ORS's rationale for the recommendation, ORS Witness Briseno testified that, for large utilities, the lead-lag study is the most prevalent and accepted method of calculating cash working capital, as it determines the specific number of days between the payment of the utility's bills compared to when revenue is received from customers and, in some instances, customer payment is received before the utility pays a bill Tr. 1025.25:7 – 1025.28:19. Witness Briseno pointed out that employing the lead-lag methodology is supported by industry practice, the Commission has previously ordered other utilities to perform a lead-lag study for a company's next general rate case or other regulatory proceeding, and South Carolina is the only state currently permitting DEP and other Duke Energy affiliates to utilize the $1/8^{th}$ methodology in calculating cash working capital. *Id.*

Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues between the Parties regarding the calculation of cash working capital and utilizing a lead-lag study for the Company's next general rate proceeding. Section B Paragraph 39 of the Settlement Agreement provides that the Company agrees to perform a Lead-lag Study before the next general rate proceeding and present the results to the Commission and ORS.

Commission Discussion

The Commission finds and concludes it is just and reasonable in light of all the evidence presented that the Company, prior to the commencement of its next general rate proceeding, perform a Lead-lag Study and present the results of said study to the Commission and ORS.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

(Vegetation Management)

The evidence supporting this finding of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of DEP Witness Callahan (Rebuttal); ORS Witness Bickley (Direct); and the entire record in this proceeding.

ORS Witness Bickley, through his Surrebuttal Testimony, addressed vegetation management concerns raised by customers at the public hearings and referenced in the Rebuttal Testimony of Witness Callahan Tr. 1054:16. Witness Bickley made two recommendations on behalf of ORS regarding the Company's vegetation management practices. First, Witness Bickley recommended that DEP should report to the Commission and ORS on the miles of transmission and distribution that are cut, sprayed, and maintained on a quarterly basis *Id.* Additionally, Witness Bickley sponsored ORS's recommendation for DEP to develop and provide to the Commission and ORS an annual action plan for the next twelve-month period by no later than December 31 of each year for all planned transmission and distribution miles to be maintained.

The annual action plan should include at a minimum:

(1) estimated costs for implementation during the next twelve-month period;

(2) estimated transmission and distribution miles to be maintained during the next twelve-month period;

(3) an update on actual Company activities comparing the actual costs and miles maintained to the projected costs and miles maintained during the current twelve- month period; and

(4) an affirmation that the Company has used the revenues for vegetation

management and tree trimming provided in base rates to perform all necessary and appropriate vegetation management and tree trimming activities during the current 12-month period. *Id.*

Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues between the Parties regarding the Company's vegetation management practices. Section B, Paragraph 40 and its corresponding sub-paragraphs of the Settlement Agreement provides that the Company agrees to provide a quarterly report to the Commission and ORS on the miles of transmission and distribution that are cut, sprayed, and maintained as part of DEP's tree trimming and vegetation management work. Hearing Exhibit No. 6, pp. 18-19.

Additionally, the Company agreed to provide the Commission and ORS a report on December 31 of each year for the succeeding 12-month period that details, at minimum, all planned transmission and distribution miles to be maintained on an annual basis, as well as the estimated costs for implementation, the estimated transmission and distribution miles to be maintained, and an update on actual Company activities that compares the actual costs and miles maintained to those projected from the current 12-month period. Also, DEP agreed to only deploy vegetation management funds for vegetation management and tree trimming and will provide a report detailing its level of spending to the Commission and ORS as part of the annual action plan described above.

Commission Discussion

The Commission finds and concludes Section B Paragraph 40 of the Settlement Agreement (Hearing Exhibit No. 6, pp. 18-19) to be just and reasonable in light of all the evidence presented, and that the Company undertake the vegetation management activities as detailed in that provision of the Settlement Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37-38

(Grid Improvement Plan and Distribution Planning)

The evidence supporting these findings of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of DEP Witness Guyton (Rebuttal); SACE, CCL and Vote Solar Witness Hill (Direct and Surrebuttal), and the entire record in this proceeding.

Witness David Hill, appearing on behalf of SACE, CCL and Vote Solar, filed Direct Testimony that concluded, based on his review, that there were opportunities to engage stakeholders more deeply in the development, design, and prioritization aspects of GIP planning. Tr. 964.9:9-12. Witness Hill additionally testified that the Company's GIP did not assess multi-sited distributed energy resources and non-traditional solutions (NTS) or reflect efforts to target or benefit low- and moderate-income households, such as by addressing variability in service due to demographics or identifying ways to serve environmental justice communities. Tr. 964.8:5-964.9:18.

Company Witness Brent C. Guyton responded to the recommendations made by Witness Hill in his Rebuttal Testimony. Specifically, Witness Guyton testified that the Company has held five virtual forums for external GIP stakeholders that were interested, and the efforts related to those sessions are documented in Docket No. ND-2020-28-E. Tr. 844.32:14-844.33:12. Witness Guyton also stated that the issues raised by Witness Hill's Direct Testimony were not shared in the stakeholder engagement sessions. Tr. 844.35:1-3. Regarding potential gaps in the GIP, Witness Guyton testified that environmental justice is considered in DEP's screening process for generation sites, though not expressly incorporated into GIP planning. Tr. 844.30:14-16. However, he went on to explain that DEP relies heavily on its community relations and stakeholder engagement teams to proactively communicate with those who are directly affected by infrastructure projects. *Id.*, 16-18.

In his Surrebuttal Testimony, Witness Hill testified that Witness Guyton's response distorted the purpose of stakeholder processes as a consensus building tool and ignored the ways in which his recommendations and examples from other jurisdictions can be used to improve stakeholder engagement Tr. 966.2:3-13. Witness Hill also testified that while he had not participated in the stakeholder process, the issues he raised in his Direct Testimony were raised in past stakeholder meetings but were not incorporated into the Company's GIP. Tr. 966.8:7-9. Witness Hill testified that the Company's efforts to address equity in other contexts like generation siting confirms that it should also be expressly considering equity and environmental justice in the GIP. Tr. 966.2:14-966.3:14.

Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues in this case regarding the Integrated Systems and Operations (ISOP) stakeholder process. The Settlement Agreement provides for the Company to build upon the existing ISOP stakeholder process to inform and contribute to future GIP and, biannually, to submit informational reports to the Commission on the status of the ISOP process, including a summary of stakeholder recommendations, through December 31, 2024. The distribution planning focus in the ISOP stakeholder process will include sharing data concerning distribution NTS, opportunities for stakeholders to provide inputs and recommendations on the Company's distribution NTS planning framework and analyses, and an opportunity to review and provide feedback on the results. Each iteration of the distribution NTS screening process will include identification of candidates for the development of distribution NTS.

In addition, the Company agrees, subsequent to the release of its Climate Risk & Resilience Study Final Report, to work collaboratively with stakeholders, to include members of the community, to discuss and work in good faith to develop and implement at least one potential target initiative as part of its GIP, to be informed by the final report, subject to approval by the Commission and included in an informational filing described in Section B, Paragraph 41 of the Settlement Agreement. Hearing Exhibit No. 6, pp. 19-20. As part of this provision, the Company shall evaluate the effectiveness of any implementation plans developed for the initiatives for potential use in expanded initiatives and budgeting in future GIPs, placing emphasis on those initiatives designed to address equity or environmental justice issues while also demonstrating the use of distributed energy resources as NTS. Per Section B, Paragraph 48 of the Settlement Agreement (Hearing Exhibit No. 6, p. 21), Settling Parties have not taken a position on the underlying merits of these commitments, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the commitments described. Hearing Exhibit No. 6, p. 21.

Commission Discussion

The Commission finds and concludes that the agreed-upon provisions outlined in Section B, Paragraphs 41-42 of the Settlement Agreement are just and reasonable in light of all the evidence presented. Settlement Agreement, pp. 19-20.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

(Energy Efficiency Opportunities)

The evidence supporting this finding of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of SACE, CCL and Vote Solar Witness Grevatt (Direct, Surrebuttal, and Settlement) (Hearing Exhibit No. 66) and DEP Witness Byrd (Rebuttal); and the entire record in this proceeding.

Witness Jim Grevatt, appearing on behalf of SACE, CCL and Vote Solar, filed Direct Testimony recommending that the Commission direct the Company to increase the availability of energy efficiency opportunities to mitigate, at least in part, the impacts of its proposed rate increase, particularly for low-to-moderate income residential customers. Tr.939.5:6-9. In support, Witness Grevatt showed the existing energy burdens in DEP's service territory and illustrated how the rate increase would exacerbate those burdens. Tr. 939.14:4-939.19:2. Witness Grevatt made specific recommendations for the Company to increase investment in the Neighborhood Energy Saver (NES) program, increase the comprehensive energy savings measures associated with the enhanced NES program, increase annual weatherization investment targets, and file additional income-qualified programs for approval in South Carolina. *Id.,* 5-7.

DEP Witness Byrd filed Rebuttal Testimony contesting the appropriateness of a general rate proceeding for the recommendations related to the Company's energy efficiency programs as proposed by Witness Grevatt. Witness Byrd states that the Company's position is that a general rate case is an improper forum to address the recommendations put forward by Witness Grevatt. Tr. 834.16:8-834.17:2. Witness Byrd also notes that SACE and CCL have made many of the same arguments in the open and contested DEP South Carolina EE/DSM Rider proceeding (Docket No. 2022-255-E). Tr. 834.17:7-11.

Witness Grevatt responded to the forum issue in his Surrebuttal Testimony, stating that DEP had often made that same argument, which ignores the primary purpose of his testimony to increase energy efficiency opportunities to mitigate, at least partially, the impact of the Company's proposed rate increase for low-to-moderate income customers. Tr. 941.2-941.3.

Subsequently, the Settling Parties entered into the Settlement Agreement, which settled the contested issues in this case regarding energy efficiency opportunities and was supported in settlement testimony by Witness Grevatt. Hearing Exhibit No. 6. The Settlement Agreement provides that the Company will work with the EE/DSM Collaborative to develop and file its Income-Qualified (IQ) High-Energy Use pilot program and Tariffed On-Bill pilot program as soon as practicable, but no later than December 31, 2023, for Commission approval. *Id.* Additionally, the Company agrees to file for approval to ramp up its proposed annual investments for all IQ program costs incurred by the Company in South Carolina to at least $1,000,000 by 2025, $750,000 of which will go toward the enhanced NES program, provided evaluation shows this to be feasible and subject to Commission approval. The Company also agreed as part of the Settlement Agreement to work with the EE/DSM Collaborative to develop a plan to increase its installation of comprehensive energy savings measures associated with the enhanced NES program in South Carolina, such as air sealing, insulation, and duct sealing. *Id.* The Company further agrees to submit an informational update to the Commission with revised annual energy savings projections at the higher spending level and to work with the EE/DSM Collaborative to identify and address potential barriers to successfully deploying the additional spending. Per Section B, Paragraph 48 of the Settlement Agreement (Hearing Exhibit No. 6, p. 21), Settling Parties have not taken a position on the underlying merits of these commitments, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the commitments described. Hearing Exhibit No. 6, p. 21.

Commission Discussion

The Commission finds and concludes it is just and reasonable, in light of all the evidence presented, that the Company undertake the activities as detailed in the provisions of Section B, Paragraphs 43-45 to the Settlement Agreement. Hearing Exhibit No. 6, pp. 20-21.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 40

(Federal Inflation Reduction Act Action Plan)

The evidence supporting this finding of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of SACE, CCL and Vote Solar Witness Grevatt (Direct and Surrebuttal) (Hearing Exhibit No. 66), and the entire record in this proceeding. Hearing Exhibit Nos. 6 & 66.

SACE/CCL/Vote Solar Witness Jim Grevatt testified the Inflation Reduction Act (IRA) includes significant funding for direct rebates and purchase discounts for low-to-middle income households to improve the efficiency of their homes and listed some of the efficiency upgrades and corresponding rebate caps in his Direct Testimony. Tr. 939.34. Witness Grevatt stated that DEP could facilitate participation in the IRA and coordinate program delivery to leverage funding for vulnerable customers, as well as facilitate access to IRA rebates and tax credits for those customers who do not otherwise meet the income thresholds for the Company's low-income programs Tr.939.34-939.35.

The Settling Parties subsequently entered into the Settlement Agreement (Hearing Exhibit No. 6), which settled the issues between the parties regarding the Company's role with respect to the IRA. Pursuant to the Settlement Agreement, the Company also agrees to develop a plan for integrated customer participation in the IRA for customers who participate in its IQ programs to maximize and expand benefits to highly electric energy burdened households and to develop a plan to support all of its customers' participation in the opportunities created by the IRA (e.g., helping customers understand which measures qualify for IRA rebates and tax credits). Pursuant to the Settlement Agreement (Hearing Exhibit No. 6), the Company will endeavor to have a final action plan ready to be filed concurrently with the announced availability of IRA rebates in South Carolina and offer to preview the final action plan with ORS. Per Section B, Paragraph 48 of the Settlement Agreement (Hearing Exhibit No. 6, p. 21), Settling Parties have not taken a position on the underlying merits of these commitments, and reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the commitments described. Hearing Exhibit No. 6, p. 21.

Commission Discussion

The Commission finds and concludes that for the present case, the agreed-upon provision of the Settlement Agreement in Section B Paragraph 47 is just and reasonable in light of the entirety of the evidence presented. *Id.*

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41

(Electric Energy Burden)

The evidence supporting these findings of fact is found in the Verified Application, the Settlement Agreement, the testimony and exhibits of SACE/CCL/Vote Solar Witness Grevatt (Direct) (Hearing Exhibit No. 66), and the entire record in this proceeding.

In his Direct Testimony, SACE/CCL/Vote Solar Witness Grevatt testified that energy burden is a term used to quantify the relationship between the cost of household energy use and the household income that is nominally available for paying expenses such as food, rent or mortgage, insurance, medical expenses, energy transportation, and other necessities. Tr. 939.14:4-939.20:2. He stated that in the counties DEP serves, there are over 50,000 households below 100% of federal poverty level, and that for those households, their electric bills are a staggering 18%–27% of their income. *Id.* He recommended that the Commission require DEP to analyze customers' energy burden in future rate case applications. *Id.*

The Settlement Agreement at Section B Paragraph 49 (Hearing Exhibit No. 6, p. 21) provides that the Company will address the impact of an increase in rates on overall electric energy burden in its next general rate proceeding. In his settlement Testimony, SACE/CCL/Vote Solar Witness Grevatt testified that Settlement Section B Paragraph 49 will benefit the Commission, and ultimately, customers, to better understand the impact future rate increases will have on energy burden in the Company's territory, and that the provision met his recommendation made in his Direct Testimony. Tr. 943.7:3-13; Hearing Exhibit No. 6, p. 21. Company Witness Callahan and ORS Witness Hipp also supported this provision in their Testimony in support of the Settlement Agreement. Tr. 649.5:23-649.7:2; Tr. 983.2:23-983.5:10; see also, Hearing Exhibit No. 6.

The Commission finds and concludes that for the presented case, the agreed-upon provisions of the Settlement Agreement in Section B, Paragraph 49 (Hearing Exhibit No. 6, p. 21) are just and reasonable in light of entirety of the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 42

(Pending Motions)

Throughout the course of this proceeding, various motions and filings were made. However, the Settlement Agreement at Section B, Paragraph 50 (Hearing Exhibit No. 6, p. 21) provides that the Parties agree to hold in abeyance all pending motions, including an abeyance of any deadlines to file responses and/or replies. Company Witness Callahan, ORS Witness Hipp supported this provision through their Testimony in general support of the Settlement Agreement. Tr. 649.5:1—649.7:2; Tr. 983.2:14—983.5:10; see also, Hearing Exhibit No. 6.

All Parties support Settlement Agreement Section B Paragraph 50. Hearing Exhibit No. 6, p. 21. Accordingly, the Commission finds and concludes that for the presented case, the agreed-upon provisions of the Settlement Agreement in Section B, Paragraph 50 are just and reasonable in light of entirety of the evidence presented. *Id.*

V. CONCLUSIONS OF LAW AND ORDERING PARAGRAPHS

After hearing and evaluating the testimony of the witnesses and based on the Commission's review of the Application, the Settlement Agreement, and the testimony and exhibits submitted during the hearing, the Commission adopts as just and reasonable and in the public interest all terms and provisions of the Settlement Agreement as a comprehensive resolution of all issues. Hearing Exhibit No. 6. These include:

(1) the accounting and pro forma adjustments appended to the Settlement Agreement in Attachment A (Hearing Exhibit No. 6, pp. 35-53);

(2) base rates generating a revenue increase of approximately $52,297,000;

(3) rates established based on a 9.6% ROE, a 3.77% cost of debt, and a capital structure that includes 47.57% debt and 52.43% common equity; and

(4) adopting the proposed revenue increases by class and the respective rates of return in Settlement Agreement Attachment B. Hearing Exhibit No. 6, p. 54.

Lastly, the Company's services are adequate and are being provided in accordance with the requirements set forth in the Commission's rules and regulations pertaining to the provision of electric service.

IT IS THEREFORE ORDERED THAT:

1. The Settlement Agreement, which includes Settlement Agreement Attachments A, B, C, D and E (Hearing Exhibit No. 6), entered into by the Settling Parties to this Docket, is just and reasonable, is in the public interest, and is consistent with law and regulatory policy. Accordingly, the Settlement Agreement is approved in its entirety.

2. The calculation of the base rates required to generate approximately $52,297,000 revenue increase, exclusive of riders and mitigation measures contemplated in the Settlement Agreement, shall be established based on a 9.6% ROE, a 3.77% cost of debt, and a capital structure that includes 47.57% debt and 52.43% common equity.

3. The accounting and pro forma adjustments proposed by the Company in

its Application, and in its Testimony and exhibits filed in this proceeding, as modified by the changes in the Settlement Agreement Attachment A (Hearing Exhibit No. 6, pp. 1-53) are approved.

4. DEP shall be allowed to increase its rates and charges effective for service rendered as of April 1, 2023, so as to produce an increase in annual revenues from base rates for its South Carolina retail operations of $52,297,000, exclusive of riders and mitigation measures contemplated in the Settlement Agreement.

5. The rate design and revenue allocation proposed by the Company in its Application, and in its Testimony and exhibits filed in this proceeding, as modified by the changes agreed upon in the Settlement Agreement (Hearing Exhibit No. 6), are approved, and shall first be effective for service rendered on and after April 1, 2023.

6. The Company shall implement the rates resulting from the Settlement Agreement. *See*, Hearing Exhibit No. 6.

7. All proposals and recommendations set forth in Order Exhibit No. 1, the Settlement Agreement, are adopted. *Id.*

8. All amortization of deferred items will be at the amount established by this Order and remain in effect until the deferred balance is fully recovered or returned.

9. All other rate design and schedule changes not otherwise modified by Order Exhibit No. 1 (Hearing Exhibit No. 6) and that were proposed by the Company are adopted.

10. DEP's requested extension to the accounting order for ongoing Grid Improvement Plan costs is approved subject to the terms agreed upon in the Comprehensive Settlement Agreement as described herein and contained in Order

Exhibit No. 1.

11. DEP shall continue to file quarterly reports with the Commission and ORS showing (a) rate of return on rate base; (b) return on common equity (allocated to South Carolina retail operations); (c) earning per share of common stock; and (d) debt coverage ratio of earnings to fixed charges.

12. DEP shall continue to provide ORS with an annual update of the accumulated value of its end-of-life nuclear fund.

13. Since the Company has completed its AMI meter rollout and asserts that annual reporting is no longer needed, DEP's request to stop the annual AMI reporting requirement required by Order No. 2019-341 is approved.

14. Revised tariffs shall be filed by March 17, 2023. The tariffs should be electronically filed in a text searchable PDF format using the Commission's DMS System (https://dms.psc.sc.gov). An additional copy should be sent via email to etariff@psc.sc.gov to be included in the Commission's Tariff System (http://etariff.psc.sc.gov). Future revisions should be made using the ETariff System. The tariffs shall be consistent with the findings of this Order and agreements with the other Parties to this case. DEP shall provide a reconciliation of each tariff rate change approved as a result of this order to each tariff rate revision filed in the ETariff System. Such reconciliation shall include an explanation of any differences and be submitted separately on the Commission's DMS System.

15. The rates, fees, and charges set forth in Order Exhibit No. 1 and its attachments (Hearing Exhibit No. 6) are fair and reasonable and will allow DEP to provide its customers with reliable and high-quality electric service.

16. DEP shall issue notice to the ratepayers of expiration of the EDIT Rider and the effect on rates. This notice shall describe the rate effect of the end of the EDIT Rider and be included in customer bills during the last billing cycle before exhaustion of the EDIT Rider. DEP shall file a proposed notice for Commission approval no later than 120 days before the expiration of the EDIT Rider.

17. DEP shall charge the rates approved herein for service rendered on or after April 1, 2023.

18. The Settling Parties shall abide by all terms of the Settlement Agreement.

19. This Order shall remain in full force and effect until further order of the Commission.

PUBLIC SERVICE COMMISSION SOUTH CAROLINA

Florence P. Belser, Chair
Public Service Commission of
South Carolina

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2022-254-E

IN RE:	Application of Duke Energy Progress, LLC for Increase in Electric Rates, Adjustments in Electric Rate Schedules and Tariffs, and Request for an Accounting Order	))))	**COMPREHENSIVE SETTLEMENT AGREEMENT**

Pursuant to S.C. Code Ann. §1-23-320(F), and all other applicable statutes and regulations, this Settlement Agreement ("Settlement Agreement") is made by and among Duke Energy Progress, LLC ("DEP" or the "Company"), the South Carolina Department of Consumer Affairs ("DCA"), the United States Department of Defense and all other Federal Executive Agencies ("DOD/FEA"), South Carolina Small Business Chamber of Commerce ("SCSBCC"), Nucor Steel – South Carolina ("Nucor"), South Carolina Coastal Conservation League ("CCL"), Southern Alliance for Clean Energy ("SACE"), Vote Solar, Sierra Club, Walmart Inc. ("Walmart"), the South Carolina Energy Users Committee ("SCEUC"), and the South Carolina Office of Regulatory Staff ("ORS"), (collectively referred to as the "Settling Parties", "Parties", or sometimes individually as "Party"). Accordingly, this Settlement Agreement is comprehensive both in the scope of issues before the Public Service Commission of South Carolina ("Commission") in this proceeding as well as its inclusion of all parties of record before the Commission in this proceeding.

Exhibit
PSC 2022-254-E 6
1/17/2023 CP

WHEREAS, the Company prepared and filed on September 1, 2022, the Application of Duke Energy Progress, LLC for Increase in Electric Rates, Adjustment in Electric Rate Schedules and Tariffs, and Request for an Accounting Order ("Application");

WHEREAS, the above-captioned proceeding has been established by the Commission pursuant to the procedure set forth in S.C. Code Ann. § 58-5-240 *et seq.*, and the Parties to this Settlement Agreement are parties of record in the above-captioned docket;

WHEREAS, ORS is charged by law with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B);

WHEREAS, the DOD/FEA, SCSBCC, Nucor, CCL, SACE, Vote Solar, Sierra Club, Walmart, and SCEUC all filed timely petitions to intervene in this proceeding pursuant to S.C. Code Ann. Reg. 103-825.3;

WHEREAS, the DCA by law may advocate for the interest of consumers in matters before the Commission pursuant to S.C. Code Ann. § 37-6-604(C) and filed a timely petition to intervene in this proceeding pursuant to S.C. Code Ann. Reg. 103-825.3;

WHEREAS, ORS conducted an examination of the books and records of the Company relative to: the matters raised in the Application; test-period revenues, operating expenses, depreciation and taxes paid by the Company; rate base, plant in service, construction work in progress, working capital, capital expenditures; and other relevant accounting matters;

WHEREAS, the Parties examined all accounting and pro forma adjustments proposed by the Company, the Company's rate design, the Company's capital structure and cost of capital, and/or information related to the Company's operations;

WHEREAS, the Parties have varying positions regarding the issues in this case;

WHEREAS, the Parties have engaged in discussions to determine if a settlement of some or all of the issues would be in their best interests and, in the case of ORS, in the public interest, and in the case of DCA, in the interest of consumers; and,

WHEREAS, following those discussions, the Parties determined that their interests, the DCA determined the consumer interest,[1] and ORS determined that the public interest, would be best served by agreeing to this Settlement Agreement regarding issues raised by the Parties and pending in the above-captioned case under the terms and conditions set forth herein;

NOW, THEREFORE, the Parties hereby stipulate and agree to the following terms.

A. STIPULATION OF TESTIMONY AND WAIVER OF CROSS-EXAMINATION

1. The Parties agree to stipulate into the record before the Commission the pre-filed testimony and exhibits (collectively, the "Stipulated Testimony") of the below witnesses who have pre-filed testimony to date, including any testimony and exhibits supporting approval of this Settlement Agreement pre-filed with the Commission subsequent to the execution of this Settlement Agreement, without objection, change, or amendment with the exception of changes comparable to those that would be presented via an errata sheet or through a witness noting a correction consistent with this Settlement Agreement. The Parties agree to submit Verification for Testimony for those witnesses that will not be sworn in through live testimony. The Parties also agree to waive cross-examination of all witnesses. Further, the Parties reserve the right to engage in redirect examination of their respective witnesses (identified below) as necessary to respond to issues raised by the examination of their witnesses, if any, by non-parties, parties that are not signatories to this Settlement Agreement, or the Commission.

[1] The DCA's mission is to protect consumers from inequities in the marketplace through advocacy, mediation, enforcement, and education. Consumer interest for the purpose of DCA's representation includes South Carolina residents who purchase utility services primarily for a personal, family, or household use.

DEP witnesses:

1. Michael P. Callahan (Direct, Rebuttal, and Settlement)
2. Larry E. Hatcher (Direct)
3. Retha Hunsicker (Direct)
4. Dr. Roger Morin (Direct and Rebuttal)
5. Karl W. Newlin (Direct and Rebuttal)
6. Jacob Stewart (Direct and Rebuttal)
7. Dan Maley (Direct)
8. Brent Guyton (Direct and Rebuttal)
9. Tom Ray (Direct and Rebuttal)
10. Julie Turner (Direct and Rebuttal)
11. Jessica L. Bednarcik (Direct and Rebuttal)
12. Mark D. Rokoff (Direct and Rebuttal)
13. Marcia Williams (Direct and Rebuttal)
14. Steven M. Fetter (Direct and Rebuttal)
15. Sean Riley (Direct and Rebuttal)
16. John Spanos (Direct and Rebuttal)
17. Nicholas G. Speros (Direct)
18. Janice Hager (Direct and Rebuttal)
19. Teresa Reed (Corrected Direct, Rebuttal and Settlement)
20. Jonathan Byrd (Direct and Rebuttal)
21. Rachel R. Elliott (Direct, Supplemental Direct, Second Supplemental Direct, Rebuttal, and Settlement)
22. James L. Coyne (Rebuttal)
23. Kim H. Smith (Rebuttal)

SCEUC witness:

1. Kevin W. O'Donnell (Direct and Surrebuttal)

DCA witnesses:

1. Eric Borden (Direct and Surrebuttal)
2. David Dismukes (Direct and Surrebuttal)
3. Aaron L. Rothschild (Direct and Surrebuttal)

DOD/FEA witnesses:

1. Brian Andrews (Direct and Surrebuttal)
2. Christopher Walters (Direct and Surrebuttal)
3. Michael Gorman (Direct and Surrebuttal)

SCSBCC witness:

1. Anthony Ward (Direct)

Nucor witnesses:

1. Jeffry Pollock (Direct and Surrebuttal)
2. Billie S. LaConte (Direct and Surrebuttal)[2]

[2] Nucor Witness LaConte filed Corrected Direct Testimony and Exhibits on January 12, 2023.

SACE/CCL/Vote Solar witnesses:
1. David G. Hill, Ph.D. (Direct and Surrebuttal)
2. Jim Grevatt (Direct, Surrebuttal, and Settlement)

Walmart witness:
1. Lisa Perry (Direct and Surrebuttal)

ORS witnesses:
1. Robert Lawyer (Corrected Direct)[3]
2. Elizabeth McGlone (Direct and Surrebuttal)
3. Richard Baudino (Direct and Surrebuttal)
4. Glenn Watkins (Direct and Revised Surrebuttal)[4]
5. David Garrett (Direct and Surrebuttal)
6. Anthony Briseno (Direct and Revised Surrebuttal)[5]
7. Courtney Radley (Direct and Surrebuttal)
8. Anthony Sandonato (Direct and Surrebuttal)
9. Daniel J. Roland (Direct)[6]
10. Brandon Bickley (Direct and Surrebuttal)
11. Omari Thompson (Direct and Surrebuttal)
12. Dan Wittliff (Direct and Surrebuttal)
13. Michael Seaman-Huynh (Direct and Revised Surrebuttal)[7]
14. Shane Hyatt (Corrected Direct)[8]
15. Daniel Sullivan (Direct and Surrebuttal)
16. Aaron Rabon (Corrected Direct and Surrebuttal)[9]
17. Dawn Hipp (Direct, Revised Surrebuttal, and Settlement)[10]

2. The Parties agree to offer no other evidence in the proceeding other than the Stipulated Testimony and Exhibits and this Settlement Agreement unless the additional evidence is to support the Settlement Agreement, consists of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction or clarification, consists of a witness adopting the testimony of another if permitted by the Commission, or is responsive to issues raised by examination of the Parties' witnesses by non-Parties, parties which are not

[3] ORS Witness Lawyer filed Corrected Direct Testimony on December 2, 2022.
[4] ORS Witness Watkins filed Revised Surrebuttal Testimony on January 6, 2023.
[5] ORS Witness Briseno filed Revised Surrebuttal Testimony and Exhibits on January 6, 2023.
[6] ORS Witness Roland filed Corrected Direct Testimony on January 6, 2023.
[7] ORS Witness Seaman-Huynh filed Revised Surrebuttal Testimony and Exhibit on January 6, 2023.
[8] ORS Witness Hyatt filed Corrected Direct Testimony and Exhibits on January 6, 2023.
[9] ORS Witness Rabon filed Corrected Direct Testimony and Exhibits on January 6, 2023.
[10] ORS Witness Hipp filed Revised Surrebuttal Testimony on January 6, 2023.

signatories to this Settlement Agreement, the Commission, or by late-filed testimony by non-parties. The Parties agree that nothing herein will preclude each party from advancing its respective positions in the event that the Commission does not approve the Settlement Agreement in its entirety.

B. SETTLEMENT AGREEMENT TERMS

3. This Settlement Agreement is a compromise of all the positions advanced by the Parties. The Parties agree to and accept the proposal set out immediately below, and this proposal is hereby adopted, accepted, and acknowledged as the final agreement of the Parties.

4. The Parties agree that this Settlement Agreement is comprehensive and non-severable. This Settlement Agreement is the result of extensive negotiation and compromise among the Parties, and it resolves all issues presented including all pending motions. The Parties agree that if the Commission declines to approve the settlement in its entirety and without modification, any Party may withdraw from the Settlement Agreement and be released from its terms without penalty or obligation.

5. The Parties agree that this Settlement Agreement pertains to matters addressed in this case, and unless specified otherwise nothing in this Settlement Agreement binds Parties from taking an alternative position in any current or future proceeding in South Carolina or any other jurisdiction. The Parties agree that the Settlement Agreement terms agreed upon in this case are reasonable, in the public interest, and in accordance with South Carolina law and regulatory policy. The Parties' agreement that the terms of the Settlement Agreement are reasonable as a whole does not in any way indicate any Party's position as to the reasonableness of any single term taken out of the context of the Settlement Agreement.

6. Without prejudice to the position of any Party in any current or future proceedings unless specified otherwise, the Parties agree to accept and adopt all recommendations, adjustments, and customer protections in the testimony and exhibits of ORS witnesses, unless specifically modified by this Settlement Agreement or Attachment A to the Settlement Agreement.[11]

Revenue Increase, EDIT, Return on Common Equity, and Capital Structure

7. For purposes of this Settlement Agreement, and in recognition of the mutual compromises contained herein, the Parties further agree that the Application, Stipulated Testimony, and this Settlement Agreement conclusively demonstrate the following: (i) the proposed accounting and pro forma adjustments appended to the Settlement Agreement as Attachment A are fair and reasonable and should be adopted by the Commission for ratemaking and reporting purposes; (ii) the rates generate an annual base revenue increase equaling $52,297,000, or approximately an 8.83% increase from current rates, exclusive of riders and mitigation measures contemplated in this Settlement Agreement, to be effective April 1, 2023; (iii) the rates generate an annual net base revenue increase equaling $35,871,000, or approximately 5.81%, inclusive of riders and mitigation measures contemplated in this Settlement Agreement, to be effective April 1, 2023; (iv) the rates in this proceeding shall be based on a 9.6% return on common equity ("ROE") and a capital structure that includes 47.57% debt and 52.43% equity; (v) the Company's cost of debt is 3.77%, resulting in a weighted average cost of capital ("WACC") for the Company as a result of this proceeding of 6.83%[12]; and (vi) the Company's rates resulting from the Settlement Agreement appended as Attachment B are designed to recover the revenue

[11] Attachment A is comprised of Elliot Settlement Exhibits 1 through 3. The figures included in these exhibits assume an authorized ROE of 9.60% and a capital structure of 52.43% equity.
[12] The Company's actual weighted average cost of capital resulting from the Settlement Agreement is 6.826%.

requirement in an equitable and reasonable manner, are just and reasonable, and should be adopted by the Commission for service rendered by the Company.

8. To mitigate the rate increase contemplated in Paragraph 7 during the period of April 1, 2023 through December 31, 2025, the Company agrees to accelerate the return of deferred income tax benefits resulting from the Federal Tax Cuts and Jobs Act of 2017 ("Tax Act") through its Excess Deferred Income Taxes ("EDIT") Rider. The effect of this accelerated return is an annual rate decrease of approximately $16,426,000 beginning with service rendered on and after April 1, 2023, and concluding when the total balance of the Unprotected EDIT associated with property, plant, and equipment ("PP&E") is fully depleted in the period ending December 31, 2025. The Company agrees to continue to return the Unprotected Property related EDIT via the EDIT Rider in the manner described above until the full balance of Unprotected Property related EDIT is depleted.

9. In its Application and through testimony, the Company sought approval of an ROE of 10.20% and requested a revenue increase of approximately $89 million, or 14.5% above current rates, based on the adjusted test year data. Under the terms of the Settlement Agreement, the annual base revenue increase is approximately $52,297,000, or approximately 8.83% above current rates, which is a decrease of approximately $37 million relative to the Application and <u>before EDIT mitigation</u>.[13] <u>With the annual EDIT mitigation</u> of approximately $16,426,000 effective April 1, 2023, and ending December 31, 2025, the net annual revenue increase to customers is approximately $35,871,000, or approximately 5.81%.

[13] Exact figures provided in Attachment A.

10. With this Settlement Agreement, a residential customer using 1,000 kWh per month would see a net monthly increase of $10.95, reflecting a $15.18 increase in base rates less a $4.23 reduction due to the EDIT Rider.

Coal Ash Basin Closure Expense Adjustments (Coal Ash ARO Regulatory Asset)

11. The Company agrees to a permanent, one-time $50,000,000 disallowance on a South Carolina retail basis of coal ash basin closure costs ("CCR Costs") incurred through August 2022 associated with ORS Witness Wittliff's recommended adjustments to the Company's CCR Costs.

12. In addition to the $50,000,000 disallowance on the CCR Costs incurred through August 2022 described herein, DEP agrees to permanently forego recovery in any future cases of any remaining coal ash costs sought by DEP but not allowed for recovery by the Commission in Docket No. 2018-318-E.

13. Subject to Paragraphs 11 and 12 of this Settlement Agreement, the Parties agree to the continuation of deferred accounting treatment for CCR Costs. The deferral will include a debt return only, at the most recent Commission approved debt rate, for the deferral period and rate base treatment during the amortization period. The deferral will be subject to a review for reasonableness and prudency in the next general rate proceeding.

14. Other than the permanent disallowance of the costs identified in Paragraphs 11 and 12 of this Settlement Agreement, the disallowance of CCR Costs is solely related to this comprehensive Settlement Agreement and shall have no precedential effect on the recoverability of CCR Costs or the continuation of deferral accounting treatment in future proceedings, and the Parties reserve their rights on any other legal issues (i.e., the North Carolina Coal Ash Management

Act, U.S. Environmental Protection Agency rules and regulations, etc.) or to advance any other positions on coal ash in future cases.

15. The Settling Parties further agree that they will, prior to January 1, 2030, engage in good faith negotiations to resolve all issues and claims in connection with CCR Costs incurred by DEP after February 28, 2030. The agreement to work in good faith toward resolution shall not have any precedential effect and shall not impact or limit, in any way, a Party's ability to advance in future proceedings any legal arguments, theories, positions, etc. regarding CCR Costs. This provision does not place any obligation upon any Party to resolve those issues and claims in a future proceeding, and each Party maintains complete discretion to approve or reject any proposed settlement for those issues and claims in a future proceeding.

Expense Adjustments

16. The Parties accept the ORS recommendation to remove 50% of the costs associated with Duke Energy Corporation's ("Duke") Board of Directors ("BOD") compensation, 50% of expenses associated with directors and officers liability insurance, and 50% of all remaining BOD expenses (excluding aviation) (ORS Adjustment 33).

17. The Parties accept the ORS recommendation to limit coal inventory in base rates to thirty-five (35) days for ratemaking purposes (ORS Adjustment 28 to Company Adjustment SC6010).

18. The Parties accept the ORS recommendation to remove the fuel escalation factor from the End of Life Nuclear Reserve Adjustment (ORS Adjustment 12 to Company Adjustment SC2120).

19. The Parties accept the ORS recommendation to remove executive deferred compensation and non-qualified pension expense (ORS Adjustment 34 and ORS Adjustment 8 to Company Adjustment SC2060).

20. The Parties accept the ORS recommendations to the executive compensation adjustment (ORS Adjustment 6 to Company Adjustment SC2040).

21. For the Asheville Combined Cycle ("CC") regulatory asset, the following provisions have been agreed upon by the Parties:

a. Increase the amortization period to thirty-seven (37) years per the ORS recommendation.
b. The deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period.
c. The deferral will include depreciation, property taxes, and returns through March 2023.

22. For the CCR non-ARO regulatory asset, the following provisions have been agreed upon:

a. Increase the amortization period to seven (7) years per the ORS recommendation.
b. The deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period.
c. The deferral will include depreciation and return on known investment balance through March 2023.

23. The Parties accept the ORS recommendation in Revised Surrebuttal Testimony and Exhibits to update plant and accumulated depreciation inclusive of retirements through August 2022.

24. For the Grid Improvement Plan ("GIP") regulatory asset, the following provisions have been agreed upon by the Parties:

a. Increase the amortization period to seventeen (17) years.
b. The deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period.
c. The deferral will include depreciation, property taxes and returns through March 2023.
d. The Parties agree to the continuation of deferred accounting treatment for GIP investments until the rates effective date in the Company's next general rate case. Construction Work in Progress for GIP investments will not be included in rate base in this case. The Parties agree it is appropriate to consolidate Docket No. 2022-281-E with this docket and to resolve Docket No. 2022-281-E through this Settlement Agreement.
e. Grid investments and any continuation of deferral accounting treatment will be subject to a review for reasonableness and prudency in the next general rate proceeding. The deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period.

f. The Company will identify, quantify and record to the GIP deferred account incremental savings to the Company resulting from GIP expenditures that are placed into the regulatory asset. These savings may include, but are not limited to, reductions in operating expenses, improvements in revenue assurance, increased conservation, and reductions in peak demand.

25. For the Act 62 expense, rate case expense and the Advanced Metering Infrastructure ("AMI") deferrals, the following provisions have been agreed upon by the Parties:

a. The AMI deferral will include a debt return only (at the most recent Commission approved debt rate) for the deferral period and rate base treatment during the amortization period. The AMI deferral will include depreciation and return on known investment balance through March 2023.

b. The Act 62 and rate case expense deferrals will not receive rate base treatment during the amortization period and will not include returns during the deferral period.

c. Accept the amortization periods recommended by ORS as follows:

   i. Act 62 regulatory asset – amortization period of three (3) years;

   ii. Rate Case expense regulatory asset – amortization period of five (5) years; and

   iii. AMI expense regulatory asset – amortization period of fifteen (15) years.

26. Rate case expenses requested in this case (which include 2018 rate case expenses not previously recovered) are limited to actual and prudent expenses verified by ORS not to exceed $4.5 million. Rate case expenses are excluded from rate base.

27. The Parties accept the ORS recommendation to exclude the Roxboro Wastewater Treatment Facility from rate base, extend the amortization period to eleven (11) years and to remove the estimated dismantlement costs from the calculation of the amortization expense. DEP may charge actual dismantlement costs to the regulatory asset and continue the amortization until the regulatory asset is fully amortized, provided the ORS may review the actual dismantlement costs for reasonableness and prudence in the Company's next rate case.

28. The Parties agree that employee incentive compensation expenses shall be adjusted to exclude 50% of all Test Year incentives tied to Earnings Per Share ("EPS") and Total Shareholder Return ("TSR").

29. For Depreciation rates, the following provisions have been agreed upon by the Parties:

a. Accept the 2021 Depreciation Study. DEP shall not establish a regulatory asset to record the incremental impact of the 2021 Depreciation Study.
b. Accept the ORS recommended adjustments to the 2021 Depreciation Study for Accounts 364, 365, 368, and 369, to remove the escalation rate of 2.5%, and on the retirement date of 2033 for the Roxboro common facilities
c. Accept the Company's adjustments to the 2021 Depreciation Study for Accounts 352 and 356, Mayo Unit 1, contingency and Roxboro Units 3 and 4.

30. The Parties agree to accept the Company's recommendation to normalize storm costs over a five (5) year period (Company Adjustment SC7010).

31. The Parties agree to accept the Company's recommendation to establish a storm reserve to collect $3 million per year with the accumulated reserve not to exceed $50 million

(Company Adjustment SC7030). The Company agrees to implement the following customer protections as recommended by ORS:

a. Should the Company exceed the maximum fund amount of $50 million in customer contributions, customer funds to the Storm Reserve shall be returned to customers in DEP's next rate case proceeding.

b. The Company shall provide quarterly status reports, including at a minimum: the current balance of the storm reserve account, the total aggregate costs and expenses per storm restoration event, the type of storm or weather event (example: thunderstorm, flood, ice storm, windstorm, a named storm such as a hurricane, etc.), and the impact of the weather event on DEP's system including a summary of the types of restoration and repairs made by the Company.

c. Unless DEP receives prior approval from the Commission, the Company shall not withdraw or otherwise use the Storm Reserve funds to pay for: 1) insurance premiums; 2) the Company's expenses related to routine vegetation management; 3) rate impact mitigation; or 4) other costs or expenses incurred by the Company that are unrelated to storm damage restoration costs.

d. The Storm Reserve account may not be recorded on the books and records of an affiliate, parent, or holding company at any time. The Storm Reserve may not be combined with any other funds. In order for the Storm Reserve account to be transferred to another entity or for DEP to change the entity that would maintain control of the account, DEP shall first request and receive approval from the Commission.

e. DEP shall not use the Storm Reserve in lieu of the Property Insurance Policy to cover or otherwise pay for assets covered by the insurance policy for which, after a storm event, DEP seeks recovery via the Property Insurance Policy, without Commission approval. Should the Storm Reserve be utilized for assets listed on the Property Insurance Policy and DEP ultimately receives insurance payments, settlement, or recovery amounts from insurance carriers for claims related to a storm or weather event, then the customer contributions to the Storm Reserve should be reduced by any insurance payments, settlement, or recovery amounts received by the Company.

f. In order for DEP to request or seek a change to the annual customer contributions cap, the total account maximum cap, any of the these customer protections, or anything involving how the Storm Reserve is operated, maintained, monitored, controlled, and utilized, the Company shall be required to conduct and file with the Commission a Storm Reserve Study that, at a minimum, includes data and sufficient justification for determining a target maximum balance for the Storm Reserve account as well as a target for the maximum annual collections.

32. For Nuclear Materials and Supply Inventory ("M&S Inventory"), the following provisions have been agreed upon by the Parties:

a. Accept the Company's position that no exclusions should apply to M&S Inventory.

b. The Company is required to have an independent third-party perform a review and audit of the DEP nuclear, fossil, and hydro M&S inventory and program controls. The independent audit of M&S inventory shall be, at a minimum, for at least one (1) nuclear, one (1) fossil and one (1) hydro station by the time of the next general rate case filing, or within three (3) years of the Commission order in this rate case, whichever is sooner. The Company shall establish a long-term schedule for continuous independent audit cycles for M&S inventory (e.g., a three (3) to five (5) year rotational cycle).

33. The Parties agree that no exclusion should be applied to Plant Held for Future Use greater than four (4) years.

34. The Parties agree there will be no adjustment to Test Year Facilities Rent expense.

35. In consideration of the terms and conditions of this Settlement Agreement, the Parties agree to include $19,990 of expenses disallowed in Docket No. 2022-255-E, per the ORS recommendation, applied to the Adjust Test Year Expenses (Non-Allowables) adjustment (ORS Adjustment 9 and Company Adjustment SC2080).

36. The Parties agree to all other expense adjustments as recommended by ORS, except as provided in the provisions of this Settlement Agreement, and all necessary fallout adjustments that changed due to this Settlement Agreement.

37. The proposed accounting and pro forma adjustments are appended to the Settlement Agreement as Attachment A and the Parties agree they are fair and reasonable and should be adopted by the Commission for ratemaking and reporting purposes.

Other Matters

38. The Parties agree to the Rate Design as outlined in Attachments B through E, which reflects the following provisions:

a. A Rate Migration Adjustment of 50%.

b. The increase in revenue agreed to herein (exclusive of the EDIT mitigation) will be allocated to each Rate Class consistent with the cost of service study included in the Direct Testimony of Company Witness Hager with proforma adjustments necessary to reflect the provisions of this Settlement Agreement. Neither the cost of service study adopted solely for purposes of this Settlement Agreement nor the revenue allocation agreed to by the Parties for purposes of this Settlement Agreement shall have any precedential effect in future proceedings, and all Parties may argue for different cost allocation, rate design and revenue spread methodologies in future cases. The resulting revenue increase to each Rate Class for purposes of this Settlement Agreement shall be as follows:

Rate Class	Allocation Percentage Including Riders	Allocation Percentage Excluding Riders
RES	12.03%	12.71%
SGS	8.27%	8.83%
SGSTCLR	10.59%	11.53%
MGS	5.69%	6.06%
LGS	3.89%	3.87%
SI	6.40%	6.83%
TSS	18.44%	19.62%

ALS, SLS	14.96%	14.70%
SFL	6.80%	6.75%
SC-RETAIL	8.47%	8.83%

The allocation percentages to each Rate Class, inclusive of EDIT, are as follows:

Rate Class	**Allocation Percentage Including Riders**	**Allocation Percentage Excluding Riders**
RES	8.72%	9.20%
SGS	5.33%	5.69%
SGSTCLR	7.30%	7.95%
MGS	3.60%	3.84%
LGS	2.22%	2.21%
SI	3.86%	4.13%
TSS	14.05%	14.95%
ALS, SLS	10.19%	10.01%
SFL	3.51%	3.48%
SC-RETAIL	5.81%	6.06%

c. DEP agrees to reduce the LGS-TOU Schedule's on-peak energy charges by the reduction in the revenue requirement, exclusive of any EDIT decrements, allocated to the LGS-TOU Rate Schedule associated with this Settlement Agreement. The proposed reduction to the EDIT Rider allocated to Schedule LGS-TOU shall apply to the on-peak, off-peak, and discount energy periods.

39. The Company agrees to perform a Lead-lag Study before the next general rate proceeding and present the results to the Commission and ORS.

40. For Vegetation Management, the following provisions have been agreed upon by the Parties:

a. DEP shall report to the Commission and ORS on the miles of transmission and distribution that are cut, sprayed, and maintained as part of the tree trimming and vegetation management work plan on a quarterly basis.

b. DEP shall develop and provide to the Commission and ORS an annual action plan for the next 12-month period by no later than December 31 of each year for all planned transmission and distribution miles to be maintained. The annual action plan should include but is not limited to: 1) estimated costs for implementation; 2) estimated transmission and distribution miles to be maintained; and 3) an update on actual Company activities comparing the actual costs and miles maintained compared to the projected costs and miles maintained from the current 12-month period.

c. DEP shall deploy the vegetation management funds for only vegetation management and tree trimming. DEP shall report its level of spending to the Commission and ORS as part of the annual action plan.

41. The Company agrees to build upon the existing Integrated System & Operations Planning ("ISOP") stakeholder process to inform and contribute to future GIPs and commits to submit biannual informational reports to the Commission on the status of the ISOP process, including a summary of stakeholder recommendations, through December 31, 2024. This distribution planning focus in the ISOP stakeholder process will include sharing data about distribution Non-Traditional Solutions ("NTS"), opportunities for stakeholders to provide inputs and recommendations on the Company's distribution NTS planning framework and analyses, and an opportunity to review and provide iterative feedback on results. Each iteration of this

distribution NTS screening process will include identification of candidates for the development of distribution NTS.

42. Following the release of the Company's Climate Risk & Resilience Study Final Report, the Company agrees to work collaboratively with stakeholders, including community members, to discuss and work in good faith to develop and implement at least one potential target initiative as part of its GIP, to be informed by the Final Report, subject to Commission approval. and included in an informational filing as described in Paragraph 41 above. The Company shall evaluate the effectiveness of any implementation plans developed for the initiatives for potential use in expanded initiatives and budgeting in future GIPs. In considering potential initiatives, emphasis should be placed on those initiatives designed to address equity or environmental justice issues while also demonstrating the use of distributed energy resources as NTS.

43. The Company agrees to work with the EE/DSM Collaborative to develop and file for approval by the Commission its Income-Qualified ("IQ") High-Energy Use pilot program and a Tariffed On-Bill pilot program as soon as practicable, but no later than December 31, 2023.

44. The Company agrees to file for approval to ramp up its proposed annual investments for all IQ program costs incurred by the Company in South Carolina to at least $1,000,000 by 2025, $750,000 of which will go toward the enhanced Neighborhood Energy Saver ("NES") program, provided evaluation shows this to be feasible and subject to Commission approval.

45. The Company agrees to work with the EE/DSM Collaborative to develop a plan to increase its installation of comprehensive energy savings measures associated with the enhanced NES program in South Carolina, such as air sealing, insulation, and duct sealing. The Company further agrees to submit an informational update to the Commission with revised annual energy

savings projections at the higher spending level and to work with the EE/DSM Collaborative to identify and address potential barriers to successfully deploying the additional spending.

46. The Company agrees to work with the EE/DSM Collaborative to develop a plan for integrated customer participation in the Inflation Reduction Act ("IRA") for customers who participate in its IQ programs to maximize and expand benefits to highly electric energy burdened households; the Company will endeavor to have a final plan ready to be filed concurrently with the announced availability of IRA rebates in South Carolina.

47. The Company agrees to develop and implement an action plan to support all of its customers by participating in the opportunities created by the IRA, such as by helping customers to understand which measures qualify for IRA rebates and tax credits and how they can find a contractor and comply with application criteria. The Company will endeavor to have a final action plan ready to be filed concurrently with the announced availability of IRA rebates in South Carolina. The Company will offer to preview the final action plan with the ORS.

48. All Parties to this Settlement Agreement reserve their rights to review, challenge, support, and raise any issues or legal arguments regarding the programs or initiatives described in Paragraphs 41 through 47. No Party can assert that the terms in Paragraphs 41 through 47 convey an express or implied consent with the underlying merits of the commitments made in Paragraph 41 through 47.

49. The Company agrees to address the impact of an increase in rates on overall electric energy burden in its next general rate proceeding.

50. The Parties agree to hold in abeyance all pending motions, including an abeyance of any deadlines to file responses and/or replies.

C. REMAINING SETTLEMENT AGREEMENT TERMS AND CONDITIONS

51. The Parties agree that this Settlement Agreement is reasonable, is in the public interest, is in accordance with law and regulatory policy, and agree to support the resolution of issues agreed to herein in this proceeding and not to undertake any action to undermine that support. This Settlement Agreement in no way constitutes a waiver or acceptance of the position of any Party or its affiliates in any current or future proceeding in South Carolina or any other jurisdiction. Except as specifically provided otherwise previously herein, this Settlement Agreement does not establish any precedent with respect to the issues resolved herein and in no way precludes any Party from advocating an alternative position in any current or future proceeding in South Carolina or any other jurisdiction.

52. ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code § 58-4-10(B), which reads in part:

> . . . 'public interest' means the concerns of the using and consuming public with respect to public utility services, regardless of the class of customer and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services.

ORS believes this Settlement Agreement reached among the Parties is in the public interest as defined above.

53. The Parties agree that this Settlement Agreement must be read and construed as a whole and to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission in its entirety as a fair, reasonable and full resolution of the issues set forth in the Company's Application and described herein. The Parties agree to use reasonable efforts before any reviewing court in the event of appeal

to defend and support any Commission order issued approving this Settlement Agreement and the terms and conditions contained herein.

54. The Parties offer this Settlement Agreement to the Commission in its entirety as a comprehensive settlement which is the product of intensive and extensive negotiations between the Parties. The Parties agree that this Settlement Agreement confers benefits to Parties in exchange for concessions by Parties. As such, the Parties ask the Commission to approve this Settlement Agreement in its entirety without exception, modification, or additional provisions.

55. The Parties on behalf of themselves and their agents (including but not limited to their attorneys, hired consultants, and any independent contractors) agree that they have entered into this Settlement Agreement freely and voluntarily and that none of them have been pressured or unduly encouraged to enter into this Settlement Agreement.

56. Except as specifically provided otherwise previously herein or as necessary to effectuate the terms of this Settlement Agreement, the Parties agree that signing this Settlement Agreement (a) will not constrain, inhibit, impair, or prejudice them or their affiliates' arguments or positions held in future or collateral proceedings; (b) will not constitute a precedent or evidence of acceptable practice in future proceedings; and (c) will not limit the relief, rates, recovery, or rates of return that any Party may seek or advocate for in any future proceeding. If the Commission declines to approve this Settlement Agreement in its entirety and without modification, then any Party may withdraw from the Settlement Agreement without penalty or further obligation.

57. This Settlement Agreement shall be interpreted according to South Carolina law.

58. This Settlement Agreement contains the final and complete agreement of the Parties. There are no other terms or conditions to which the Parties have agreed.

59. The Parties represent that the terms of this Settlement Agreement are based upon full and accurate information known as of the date this Settlement Agreement is executed. If, after execution, but prior to a Commission decision on the merits of this proceeding, a Party is made aware of information that conflicts, nullifies, or is otherwise materially different than the information upon which this Settlement Agreement is based, that Party may withdraw from the Settlement Agreement with written notice to every other Party.

60. This Settlement Agreement shall bind and inure to the benefit of each of the signatories hereto and their representatives, predecessors, successors, assigns, agents, shareholders, officers, directors (in their individual and representative capacities), subsidiaries, affiliates, parent corporations, if any, joint ventures, heirs, executors, administrators, trustees, and attorneys.

61. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Settlement Agreement, by affixing its signature or by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the Settlement Agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement.

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Attachment A

DUKE ENERGY PROGRESS, LLC
OPERATING INCOME FROM ELECTRIC OPERATIONS
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

			South Carolina Retail Operations				
Line No.	Description	Total Company Per Books (a) (Col. 1)	Per Books (Col. 2)	Accounting Adjustments (c) (Col. 3)	Before Proposed Increase (Col. 4)	Revenue and Expenses from Proposed Increase (e) (Col. 5)	After Proposed Increase (Col. 6)
1	Electric operating revenue	$ 5,672,153	$ 574,140	$ 47,605	$ 621,745	$ 52,297	$ 674,042
	Electric operating expenses:						
	Operation and maintenance:						
2	Fuel used in electric generation	1,274,999	121,830	37,814	159,644	-	159,644
3	Purchased power	502,937	41,274	22,158	63,432	-	63,432
4	Other operation and maintenance expense	1,324,856	139,488	(9,164)	130,324	-	130,324
5	Depreciation and amortization	1,107,014	104,499	29,873	134,372	-	134,372
6	General taxes	159,530	28,033	941	28,974	272	29,246
7	Interest on customer deposits	10,049 (b)	634	-	634	-	634
8	EDIT Amortization	(155,407)	(8,041)	8,041	-	-	-
9	Net income taxes	231,477	27,415	(9,373)	18,042	12,980	31,022
10	Amortization of investment tax credit	(3,756)	(354)	(3)	(357)	-	(357)
11	Total electric operating expenses (Sum L2:L10)	$ 4,451,701	$ 454,778	$ 80,289	$ 535,067	$ 13,252	$ 548,319
12	Operating income (L1 - L11)	$ 1,220,452	$ 119,362	$ (32,684)	$ 86,678	$ 39,045	$ 125,724
13	Customer Growth				212	96	308
14	Net operating income for return (L12 + L13)	$ 1,220,452	$ 119,362	$ (32,684)	$ 86,891	$ 39,141	$ 126,032
15	Original cost rate base	$ 17,439,462	$ 1,733,416	$ 112,768 (d)	$ 1,846,184		$ 1,846,184
16	Rate of return on South Carolina retail rate base (L14/L15)		6.89%		4.71%		6.83%

-- Some totals may not foot or compute due to rounding.

Notes (a) Per Cost of Service
(b) Reclassifies interest on customer deposits to electric operating expense
(c) From Page 3b, Column 33
(d) From Page 4, Line 10, Column 3
(e) From Page 2

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Attachment A

DUKE ENERGY PROGRESS, LLC
CALCULATION OF ADDITIONAL REVENUE REQUIREMENT
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars In Thousands)

				South Carolina Retail Operations					
				Before Proposed Increase			After Proposed Increase		
Line No.	Description	Dec. 31, 2021 Amount (Col. 1)	Pro forma Ratio (Col. 2)	Retail Rate Base (Col. 3)	Embedded Cost/ Return % (Col. 4)	Operating Income (Col. 5)	Retail Rate Base (Col. 6)	Embedded Cost/ Return % (Col. 7)	Operating Income (Col. 8)
1	Long-term debt	$ 8,404,171 (a)	47.57%	$ 878,230	3.77%	$ 33,109	$ 878,230	3.77%	$ 33,109
2	Common equity	9,830,900	52.43%	967,954	5.56%	53,781	967,954	9.60%	$ 92,924
3	Total (L1 + L2)	$ 18,235,071	100%	$ 1,846,184 (b)		$ 86,891 (c)	$ 1,846,184 (d)		$ 126,033
4	Operating income before increase (Line 3, Column 5)								$ 86,891
5	Additional operating income required (L3 - L4)								$ 39,142
6	Customer growth (L5 x 0.24486%)								$ 96
7	Additional operating income required, adjusted for customer growth (L5 - L6)								$ 39,046
8	Gross receipts taxes (0.300%) and utility assessment (0 22026%)								$ 272
9	Income Taxes								$ 12,980
10	Additional revenue requiremen (L7 + L8 + L9)								$ 52,297

-- Some totals may not foot or compute due to rounding

Notes: (a) Current long-term debt maturities are excluded
(b) From Page 1, Line 15, Column 4
(c) From Page 1, Line 14, Column 4
(d) From Page 1, Line 15, Column 6

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Attachment A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH CAROLINA RETAIL
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Impacted Income Statement Line Items	Annualize Retail Revenues for Current Rates SC1010 (Col. 1)	Eliminate Unbilled Revenues SC1020 (Col. 2)	Adjust Other Revenue SC1030 (Col. 3)	Update Fuel Costs to Approved Rates SC2010 (Col. 4)	Eliminate Cost Recovered through Non-Fuel Riders SC2030 (Col. 5)	Adjust O&M for Executive Compensation SC2040 (Col. 6)	Normalize O&M Labor Expenses SC2050 (Col. 7)	Update Benefits Costs SC2060 (Col. 8)	Adjust Test Year Expenses SC2080 (Col. 9)	Adjust Aviation Expenses SC2090 (Col. 10)	Levelize Nuclear Refueling Outage Costs SC2100 (Col. 11)
1	Sales of Electricity	57,864	(5,792)	-	2,212	-	-	-	-	-	-	-
2	Other Revenue	-	-	(527)	-	(6,152)	-	-	-	-	-	-
3	Electric operating revenue (L1 + L2)	$ 57,864	$ (5,792)	$ (527)	$ 2,212	$ (6,152)	$ -	$ -	$ -	$ -	$ -	$ -
	Electric operating expenses.											
	Operation and maintenance											
4	Fuel used in electric generation	-	-	-	37,814	-	-	-	-	-	-	-
5	Purchased power	-	-	-	22,158	-	-	-	-	-	-	-
6	Other operation and maintenance expense	127	-	(1)	-	(10,089)	(154)	(1,928)	121	(4,290)	(193)	34
7	Depreciation and amortization	-	-	-	-	1,960	-	-	-	-	-	-
8	General taxes	174	(17)	(2)	-	(1,048)	(4)	(85)	-	-	(3)	-
9	Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-
10	EDIT Amortization	-	-	-	-	8,041	-	-	-	-	-	-
11	Net income taxes	14,362	(1,441)	(131)	(14,411)	755	40	502	(30)	1,070	49	(8)
12	Amortization of investment tax credit	-	-	-	-	-	-	-	-	-	-	-
13	Total electric operating expenses (Sum L4:L12)	$ 14,663	$ (1,458)	$ (134)	$ 45,561	$ (381)	$ (119)	$ (1,511)	$ 91	$ (3,220)	$ (147)	$ 26
14	Operating income (L3 - L13)	$ 43,201	$ (4,334)	$ (394)	$ (43,349)	$ (5,771)	$ 119	$ 1,511	$ (91)	$ 3,220	$ 147	$ (26)
15	Operating Income revenue requirement impact	$ (57,864)	$ 5,805	$ 527	$ 58,062	$ 7,729	$ (160)	$ (2,024)	$ 122	$ (4,312)	$ (197)	$ 34

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Settlement

Attachment A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH CAROLINA RETAIL
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Impacted Income Statement Line Items	Adjust Reserve for End-of-Life Nuclear Costs SC2120 (Col. 12)	Annualize Depreciation on Year-End Plant Balances SC3010 (Col. 13)	Annualize Property Taxes on Year-End Plant Balances SC3020 (Col. 14)	Adjust for Post Test Year Additions to Plant in Service SC3030 (Col. 15)	Adjust Depreciation for New Depreciation Rates SC3040 (Col. 16)	Add CWIP in Rate Base SC3050 (Col. 17)	Remove NCEMPA Acquistion Adjustment SC3060 (Col. 18)	Amortize Roxboro Wastewater Treatment Plant Costs SC3090 (Col 19)	Amortize Deferred Environmental ARO Costs SC4010 (Col. 20)	Remove Expiring Amortizations SC5010 (Col. 21)	Amortize Rate Case Costs SC5020 (Col. 22)	Amortize Deferred Environmental Non-ARO Costs SC5030 (Col. 23)
1	Sales of Electricity	-	-	-	-	-	-	-	-	-	-	-	-
2	Other Revenue	-	-	-	-	-	-	-	-	-	-	-	-
3	Electric operating revenue (L1 + L2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Electric operating expenses:												
	Operation and maintenance:												
4	Fuel used in electric generation	-	-	-	-	-	-	-	-	-	-	-	-
5	Purchased power	-	-	-	-	-	-	-	-	-	-	-	-
6	Other operation and maintenance expense	-	-	-	-	-	-	-	-	-	(577)	900	-
7	Depreciation and amortization	(1,857)	14,937	-	-	9,170	-	(1,156)	177	7,544	(5,043)	-	1,089
8	General taxes	-	-	1,928	-	-	-	-	-	-	-	-	-
9	Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-	-
10	EDIT Amortization	-	-	-	-	-	-	-	-	-	-	-	-
11	Net income taxes	463	(3,727)	(481)	-	(2,288)	-	288	(44)	(1,882)	1,402	(225)	(272)
12	Amortization of investment tax credit	-	(3)	-	-	-	-	-	-	-	-	-	-
13	Total electric operating expenses (Sum L4 L12)	$ (1,394)	$ 11,208	$ 1,447	$ -	$ 6,882	$ -	$ (867)	$ 133	$ 5,662	$ (4,218)	$ 675	$ 817
14	Operating income (L3 - L13)	$ 1,394	$ (11,208)	$ (1,447)	$ -	$ (6,882)	$ -	$ 867	$ (133)	$ (5,662)	$ 4,218	$ (675)	$ (817)
15	Operating Income revenue requirement impact	$ (1,867)	$ 15,012	$ 1,938	$ -	$ 9,218	$ -	$ (1,162)	$ 178	$ 7,584	$ (5,650)	$ 905	$ 1,094

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Attachment A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH CAROLINA RETAIL
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars In Thousands)

Line No.	Impacted Income Statement Line Items	Amortize Deferred Grid Costs SC5040 (Col. 24)	Adjust Approved Regulatory Assets and Liabilities SC5080 (Col. 25)	Amortize Deferred SC AMI Costs SC5100 (Col. 26)	Amortize Deferred Asheville Combined Cycle Costs SC5110 (Col. 27)	Amortized Deferred S.C. Act No 62 Costs SC5140 (Col. 28)	Adjust Coal Inventory SC6010 (Col. 29)	Adjust 1/8 O&M for accounting and pro-forma adjustments SC6020 (Col. 30)	Synchronize Interest Expense SC6030 (Col. 31)	Normalize Storm Costs SC7010 (Col. 32)	Adjust for Storm Reserve SC7030 (Col. 33)	Total (Col. 34)
1	Sales of Electricity	-	-	-	-	-	-	-	-	-	-	$ 54,284
2	Other Revenue	-	-	-	-	-	-	-	-	-	-	$ (6,679)
3	Electric operating revenue (L1 + L2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,605
	Electric operating expenses:											
	Operation and maintenance											
4	Fuel used in electric generation	-	-	-	-	-	-	-	-	-	-	$ 37,814
5	Purchased power	-	-	-	-	-	-	-	-	-	-	$ 22,158
6	Other operation and maintenance expense	-	-	-	-	682	-	-	-	3,204	3,000	$ (9,164)
7	Depreciation and amortization	1,631	309	677	435	-	-	-	-	-	-	$ 29,873
8	General taxes	-	-	-	-	-	-	-	-	-	-	$ 941
9	Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	$ -
10	EDIT Amortization	-	-	-	-	-	-	-	-	-	-	$ 8,041
11	Net income taxes	(407)	(77)	(169)	(109)	(170)	-	-	(885)	(799)	(749)	$ (9,373)
12	Amortization of investment tax credit	-	-	-	-	-	-	-	-	-	-	$ (3)
13	Total electric operating expenses (Sum L4:L12)	$ 1,224	$ 232	$ 508	$ 327	$ 512	$ -	$ -	$ (885)	$ 2,405	$ 2,252	$ 80,289
14	Operating income (L3 - L13)	$ (1,224)	$ (232)	$ (508)	$ (327)	$ (512)	$ -	$ -	$ 885	$ (2,405)	$ (2,252)	$ (32,684)
15	Operating Income revenue requirement impact	$ 1,639	$ 310	$ 680	$ 437	$ 686	$ -	$ -	$ (1,186)	$ 3,221	$ 3,016	$ 43,777

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Attachment A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH CAROLINA RETAIL
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars In Thousands)

Line No.	Rate Base		Annualize Retail Revenues for Current Rates SC1010	Eliminate Unbilled Revenues SC1020	Adjust Other Revenue SC1030	Update Fuel Costs to Approved Rates SC2010	Eliminate Cost Recovered through Non-Fuel Riders SC2030	Adjust O&M for Executive Compensation SC2040	Normalize O&M Labor Expenses SC2050	Update Benefits Costs SC2060	Adjust Test Year Expenses SC2080	Adjust Aviation Expenses SC2090	Levelize Nuclear Refueling Outage Costs SC2100
			(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col. 10)	(Col. 11)
16	Electric plant in service		-	-	-	-	(30,631)	-	-	-	-	-	-
17	Accumulated depreciation and amortization		-	-	-	-	11,526	-	-	-	-	-	-
18	Net electric plant in service (L16 + L17)		$ -	$ -	$ -	$ -	$ (19,105)	$ -	$ -	$ -	$ -	$ -	$ -
19	Materials and supplies		-	-	-	-	-	-	-	-	-	-	-
	Other Working Capital												
20	Customer deposits		-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital		-	-	-	-	-	-	-	-	-	-	-
22	Unamortized debt		-	-	-	-	-	-	-	-	-	-	-
23	Required Bank Balance		-	-	-	-	-	-	-	-	-	-	-
24	SFAS-158		-	-	-	-	-	-	-	-	-	-	-
25	Prepayments		-	-	-	-	-	-	-	-	-	-	-
26	Average Taxes Accrual		-	-	-	-	-	-	-	-	-	-	-
27	Injuries and Damages		-	-	-	-	-	-	-	-	-	-	-
28	Coal Ash Spend		-	-	-	-	-	-	-	-	-	-	-
29	Excess Deferred Income Taxes		-	-	-	-	-	-	-	-	-	-	-
30	Other		-	-	-	(7,236)	(21,870)	-	-	(856)	-	-	-
31	Total Working Capital (Sum L20:30)		$ -	$ -	$ -	$ (7,236)	$ (21,870)	$ -	$ -	$ (856)	$ -	$ -	$ -
32	Accumulated deferred income taxes		-	-	-	1,805	8,958	-	-	214	-	-	-
33	Operating reserves		-	-	-	-	-	-	-	-	-	-	-
34	Construction Work in Progress		-	-	-	-	-	-	-	-	-	-	-
35	Plant Held for Future Use		-	-	-	-	-	-	-	-	-	-	-
36	Total Initial cost rate base (L18 + L19 + SUM(L31:L35)		$ -	$ -	$ -	$ (5,431)	$ (32,017)	$ -	$ -	$ (642)	$ -	$ -	$ -
37	Rate Base revenue requirement impact		$ -	$ -	$ -	$ (497)	$ (2,928)	$ -	$ -	$ (59)	$ -	$ -	$ -
38	Total Revenue requirement impact (L15+L37)	[1]	$ (57,864)	$ 5,805	$ 527	$ 57,566	$ 4,802	$ (160)	$ (2,024)	$ 63	$ (4,312)	$ (197)	$ 34

Notes: [1] Does not include the impact of customer growth that is incorporated into the total revenue requirement calculation on Page 2

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Attachment A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH CAROLINA RETAIL
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars In Thousands)

Line No.	Rate Base	Adjust Reserve for End-of-Life Nuclear Costs SC2120 (Col. 12)	Annualize Depreciation on Year-End Plant Balances SC3010 (Col. 13)	Annualize Property Taxes on Year-End Plant Balances SC3020 (Col. 14)	Adjust for Post Test Year Additions to Plant in Service SC3030 (Col. 15)	Adjust Depreciation for New Depreciation Rates SC3040 (Col. 16)	Add CWIP in Rate Base SC3050 (Col. 17)	Remove NCEMPA Acquistion Adjustment SC3060 (Col. 18)	Amortize Roxboro Wastewater Treatment Plant Costs SC3090 (Col. 19)	Amortize Deferred Environmental ARO Costs SC4010 (Col. 20)	Remove Expiring Amortizations SC5010 (Col. 21)	Amortize Rate Case Costs SC5020 (Col. 22)	Amortize Deferred Environmental Non-ARO Costs SC5030 (Col. 23)
16	Electric plant in service	-	-	-	70,758	-	-	(31,681)	-	-	-	-	-
17	Accumulated depreciation and amortization	-	(4,486)	-	(43,881)	(9,170)	-	8,185	-	-	-	-	-
18	Net electric plant in service (L16 + L17)	$ -	$ (4,486)	$ -	$ 26,877	$ (9,170)	$ -	$ (23,496)	$ -	$ -	$ -	$ -	$ -
19	Materials and supplies	-	-	-	-	-	-	-	-	-	-	-	-
	Other Working Capital												
20	Customer deposits	-	-	-	-	-	-	-	-	-	-	-	-
21	Cash Working Capital	-	-	-	-	-	-	-	-	-	-	-	-
22	Unamortized debt	-	-	-	-	-	-	-	-	-	-	-	-
23	Required Bank Balance	-	-	-	-	-	-	-	-	-	-	-	-
24	SFAS-158	-	-	-	-	-	-	-	-	-	-	-	-
25	Prepayments	-	-	-	-	-	-	-	-	-	-	-	-
26	Average Taxes Accrual	-	-	-	-	-	-	-	-	-	-	-	-
27	Injuries and Damages	-	-	-	-	-	-	-	-	-	-	-	-
28	Coal Ash Spend	-	-	-	-	-	-	-	-	45,265	-	-	-
29	Excess Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-
30	Other	-	-	-	-	-	-	-	-	-	(1,846)	(2,039)	6,532
31	Total Working Capital (Sum L20:30)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,265	$ (1,846)	$ (2,039)	$ 6,532
32	Accumulated deferred income taxes	-	-	-	-	-	-	-	-	(11,294)	460	509	(1,630)
33	Operating reserves	-	-	-	-	-	-	-	-	-	-	-	-
34	Construction Work in Progress	-	-	-	-	-	86,259	-	-	-	-	-	-
35	Plant Held for Future Use	-	-	-	-	-	-	-	-	-	-	-	-
36	Total Initial cost rate base (L18 + L19 + SUM(L31:L35)	$ -	$ (4,486)	$ -	$ 26,877	$ (9,170)	$ 86,259	$ (23,496)	$ -	$ 33,971	$ (1,385)	$ (1,531)	$ 4,902
37	Rate Base revenue requirement impact	$ -	$ (410)	$ -	$ 2,458	$ (838)	$ 7,887	$ (2,148)	$ -	$ 3,106	$ (127)	$ (140)	$ 448
38	Total Revenue requirement impact (L15+L37) [1]	$ (1,867)	$ 14,601	$ 1,938	$ 2,458	$ 8,379	$ 7,887	$ (3,310)	$ 178	$ 10,690	$ (5,777)	$ 765	$ 1,543

Notes: [1] Does not include the impact of customer growth that is incorporated into the total revenue requirement calculation on Page 2

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Attachment A

DUKE ENERGY PROGRESS, LLC
DETAIL OF ACCOUNTING ADJUSTMENTS-SOUTH CAROLINA RETAIL
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Rate Base	Amortize Deferred Grid Costs SC5040 (Col. 24)	Adjust Approved Regulatory Assets and Liabilities SC5080 (Col. 25)	Amortize Deferred SC AMI Costs SC5100 (Col. 26)	Amortize Deferred Asheville Combined Cycle Costs SC5110 (Col. 27)	Amortized Deferred S.C. Act No 62 Costs SC5140 (Col. 28)	Adjust Coal Inventory SC6010 (Col. 29)	Adjust 1/8 O&M for accounting and pro-forma adjustments SC6020 (Col. 30)	Synchronize Interest Expense SC6030 (Col. 31)	Normalize Storm Costs SC7010 (Col. 32)	Adjust for Storm Reserve SC7030 (Col. 33)	Total (Col. 34)
16	Electric plant in service	-	-	-	-	-	-	-	-	-	-	$ 8,445
17	Accumulated depreciation and amortization	-	-	-	-	-	-	-	-	-	-	$ (37,826)
18	Net electric plant in service (L16 + L17)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (29,380)
19	Materials and supplies	-	-	-	-	-	540	-	-	-	-	$ 540
	Other Working Capital											
20	Customer deposits	-	-	-	-	-	-	-	-	-	-	$ -
21	Cash Working Capital	-	-	-	-	-	-	3,622	-	-	-	$ 3,622
22	Unamortized debt	-	-	-	-	-	-	-	-	-	-	$ -
23	Required Bank Balance	-	-	-	-	-	-	-	-	-	-	$ -
24	SFAS-158	-	-	-	-	-	-	-	-	-	-	$ -
25	Prepayments	-	-	-	-	-	-	-	-	-	-	$ -
26	Average Taxes Accrual	-	-	-	-	-	-	-	-	-	-	$ -
27	Injuries and Damages	-	-	-	-	-	-	-	-	-	-	$ -
28	Coal Ash Spend	-	-	-	-	-	-	-	-	-	-	$ 45,265
29	Excess Deferred Income Taxes	-	-	-	-	-	-	-	-	-	-	$ -
30	Other	26,093	-	9,475	15,664	(1,923)	-	-	-	-	(3,000)	$ 18,994
31	Total Working Capital (Sum L20:30)	$ 26,093	$ -	$ 9,475	$ 15,664	$ (1,923)	$ -	$ 3,622	$ -	$ -	$ (3,000)	$ 67,881
32	Accumulated deferred income taxes	(6,510)	-	(2,364)	(3,908)	480	-	-	-	-	749	$ (12,531)
33	Operating reserves	-	-	-	-	-	-	-	-	-	-	$ -
34	Construction Work in Progress	-	-	-	-	-	-	-	-	-	-	$ 86,259
35	Plant Held for Future Use	-	-	-	-	-	-	-	-	-	-	$ -
36	Total Initial cost rate base (L18 + L19 + SUM(L31:L35)	$ 19,583	$ -	$ 7,111	$ 11,756	$ (1,443)	$ 540	$ 3,622	$ -	$ -	$ (2,252)	$ 112,768
37	Rate Base revenue requirement impact	$ 1,791	$ -	$ 650	$ 1,075	$ (132)	$ 49	$ 331	$ -	$ -	$ (206)	$ 10,311
38	Total Revenue requirement impact (L15+L37) [1]	$ 3,430	$ 310	$ 1,331	$ 1,512	$ 554	$ 49	$ 331	$ (1,186)	$ 3,221	$ 2,810	$ 54,088

Notes. [1] Does not include the impact of customer growth that is incorporated into the total revenue requirement calculation on Page 2

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Attachment A

DUKE ENERGY PROGRESS, LLC
ORIGINAL COST RATE BASE-ELECTRIC OPERATIONS
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Description	Page Reference	Total Company Per Books (Col. 1)	South Carolina Retail Operations Per Books (Col. 2)	South Carolina Retail Operations Accounting Adjustments (Col. 3)	South Carolina Retail Operations As Adjusted (Col. 4)
1	Electric plant in service	4a	$ 31,835,954	$ 3,185,244	$ 8,445	$ 3,193,689
2	Less: Accumulated depreciation and amortization	4b	(12,887,184)	(1,285,316)	(37,826)	(1,323,142)
3	Net electric plant (L1 + L2)		18,948,770	1,899,928	(29,380)	1,870,547
4	Add: Materials and supplies	4c	1,054,172	92,239	540	92,779
5	Working capital investment	4d	(55,828)	(25,367)	67,881	42,513
6	Plant held for future use		52,661	5,268	-	5,268
7	Less: Accumulated deferred taxes		(2,580,679)	(240,616)	(12,531)	(253,147)
8	Operating reserves		20,366	1,964	-	1,964
9	Construction work in progress		-	-	86,259	86,259
10	Total (Sum L3:L9)		$ 17,439,462	$ 1,733,416	$ 112,768	$ 1,846,184

-- Some totals may not foot or compute due to rounding.

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Attachment A

DUKE ENERGY PROGRESS, LLC
ELECTRIC PLANT IN SERVICE AT ORIGINAL COST
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Description	Total Company Per Books (Col. 1)	South Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Plant	$ 18,042,509	$ 1,633,852	$ (23,632)	$ 1,610,220
2	Transmission Plant	3,443,502	319,904	10,137	330,042
3	Distribution Plant	8,531,324	1,042,262	6,029	1,048,291
4	General Plant	779,490	84,715	15,731	100,445
5	Intangible Plant	693,387	70,168	180	70,348
6	Subtotal (Sum L1:L5)	31,490,212 (a)	3,150,900	8,445	3,159,345
7	Nuclear Fuel (Net)	345,742	34,344	-	34,344
8	Total electric plant in service (L6 + L7)	$ 31,835,954	$ 3,185,244	$ 8,445	$ 3,193,689

-- Some totals may not foot or compute due to rounding.

Notes: (a) Excludes asset retirement obligations, plant held for future use, and certain capitalized leases.

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Attachment A

DUKE ENERGY PROGRESS, LLC
ACCUMULATED DEPRECIATION AND AMORTIZATION - ELECTRIC PLANT IN SERVICE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars In Thousands)

		Total Company	South Carolina Retail Operations		
No.	Description	Per Books (Col. 1)	Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
1	Production Reserve	$ (7,968,065)	$ (729,512)	$ (25,216)	$ (754,729)
2	Transmission Reserve	(865,062)	(80,635)	(4,045)	(84,680)
3	Distribution Reserve	(3,379,517)	(405,114)	(2,961)	(408,074)
4	General Reserve	(239,893)	(26,071)	(4,848)	(30,920)
5	Intangible Reserve	(434,646)	(43,984)	(755)	(44,740)
6	Total (Sum L1:L5)	$ (12,887,184) (a)	$ (1,285,316)	$ (37,826)	$ (1,323,142)

7 The annual composite rates (calculated based on 2021 balances) for computing depreciation are shown below:

		Plant/Other
8	Steam production plant	6.69%
9	Nuclear production plant	2.02%
10	Hydro production plant	3.67%
11	Combustion turbine production plant	3.52%
12	Transmission plant	2.34%
13	Distribution plant	2.67%
14	General plant	5.39%
15	Intangible plant	20.00%

– Some totals may not foot or compute due to rounding.

Notes: (a) Excludes asset retirement obligations

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Attachment A

DUKE ENERGY PROGRESS, LLC
MATERIALS AND SUPPLIES
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars In Thousands)

Line No.	Description	Total Company Per Books (Col. 1)	South Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)	As Adjusted (Col. 4)
	Fuel Stock:				
1	Coal	$ 93,916	$ 9,329	$ 540 (a)	$ 9,869
2	Oil	97,682	9,703	-	9,703
3	Total fuel stock (L1 + L2)	191,599	19,032	540	19,572
4	Other electric materials and supplies and stores clearing	862,573	73,206	-	73,206
5	Total Materials and Supplies (L3 + L4)	$ 1,054,172	$ 92,239	$ 540	$ 92,779

-- Some totals may not foot or compute due to rounding.

Notes: (a) Adjusts coal inventory to reflect the settled targeted inventory level of 35 days at full load.

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Attachment A

DUKE ENERGY PROGRESS, LLC
WORKING CAPITAL INVESTMENT
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Description	Total Company Per Books (Col. 1)	South Carolina Retail Operations Per Books (Col. 2)	Accounting Adjustments (Col. 3)		As Adjusted (Col. 4)
1	12 Months O&M (excluding purchase power & nuclear fuel)	$ 2,273,966	$ 228,761	$ 28,650	(a)	$ 257,411
2	Cash Working Capital (1/8 of Line 1)	$ 284,246	$ 28,595	$ 3,622	(b)	$ 32,217
3	Less: Average Tax Accruals	(69,310)	(6,951)	-		(6,951)
4	Subtotal: Investor Funds for Operations (L2 + L3)	214,936	21,644	3,622		25,266
5	Required Bank Balance	-	-	-		-
6	Unamortized Debt	50,494	5,064	-		5,064
7	Prepayments	76,388	7,660	-		7,660
8	Customer Deposits	(144,574)	(20,632)	-		(20,632)
9	SFAS 158	339,408	32,786	-		32,786
10	Coal Ash Spend	262,903	1,996	45,265		47,260
11	Excess Deferred Income Taxes	(1,294,226)	(182,979)	-		(182,979)
12	Other	438,844	109,093	18,994		128,087
13	Subtotal: Other Investor Funds (Sum L5:L12)	(270,764)	(47,012)	64,259		17,247
14	Total Working Capital Investment (L4 + L13)	$ (55,828)	$ (25,367)	$ 67,881		$ 42,513

-- Some totals may not foot or compute due to rounding.

Notes: (a) Page 3b, Column 33, Line 4 + Line 6

(b) Reflects an increase in operating funds based on 1/8 of O&M on Line 1.

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Attachment A

DUKE ENERGY PROGRESS, LLC
RECONCILIATION OF PROPOSED REVENUE REQUIREMENT
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Thousands of Dollars)

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Line No.	Item				Amount
1	Revenue requirement increase per Elliott Exhibit 1, Application			$	89,325
2	Updates made by the Company in Supplemental and Rebuttal Filings				(819)
3	Revenue requirement increase per Elliott Exhibit 1, Rebuttal Update			$	88,506
4					
5	Updated Accounting and Pro Forma Adjustments:				
6	SC2040	Adjust O&M for Executive Compensation		$	359
7	SC2050	Normalize O&M Labor Expenses			(2,202)
8	SC2060	Update Benefits Costs			(356)
9	SC2080	Adjust Test Year Expenses			(420)
10	SC2120	Adjust Reserve for End-of-Life Nuclear Costs			(228)
11	SC3010	Annualize Depreciation on Year-End Plant Balances			3,379
12	SC3020	Annualize Property Taxes on Year-End Plant Balances			592
13	SC3030	Adjust for Post Test Year Additions to Plant in Service			(8,774)
14	SC3040	Adjust Depreciation for New Depreciation Rates			8,379
15	SC3060	Remove NCEMPA Acquistion Adjustment			70
16	SC3090	Amortize Roxboro Wastewater Treatment Plant Costs			15
17	SC4010	Amortize Deferred Environmental ARO Costs			(10,936)
18	SC5020	Amortize Rate Case Costs			(338)
19	SC5030	Amortize Deferred Environmental Non-ARO Costs			(2,956)
20	SC5040	Amortize Deferred Grid Costs			(7,277)
21	SC5100	Amortize Deferred SC AMI Costs			(3,763)
22	SC5110	Amortize Deferred Asheville Combined Cycle Costs			(2,857)
23	SC5140	Amortized Deferred S.C. Act No. 62 Costs			(94)
24	SC6010	Adjust Coal Inventory			(128)
25	SC6020	Adjust 1/8 O&M for accounting and pro-forma adjustments			(25)
26	SC6030	Synchronize Interest Expense			611
27					
28	Impact of pro forma updates before customer growth and WACC updates			$	(26,948)
29					
30	Impact of change in return of equity to 9.6 percent		[1]	$	(8,209)
31	Impact of change in capital structure to 47.57/52.43 percent		[1]		(1,095)
32	Customer Growth				43
33					
34	Revenue requirement increase per Elliott Exhibit 1, Settlement Agreement			$	52,297

[1] Includes the impact on per book rate base, changes to rate base resulting from the adjustments above, and the synchronize interest expense adjustment.

Attachment A

Elliott
Exhibit 1 Page 6
Settlement

DUKE ENERGY PROGRESS, LLC
SUPPLEMENTAL CHANGES
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Thousands of Dollars)

Line No.	Item		Company Application	Settlement Agreement
1	**Base Rate**			
2	Proposed Revenue Increase - per Company's Application		$ 89,325	$ 89,325
3	Revenue Impact of Proposed Updates			(37,028)
4	Adjusted Revenue Increase		$ 89,325	$ 52,297
5				
6	**Riders**			
7	EDIT-1 Rider		$ (20,990)	$ (16,426)
8	Rate Year 1 Step-In Decrement Rider		$ (15,000)	$ -
9	Total Rider Revenue Requirement		$ (35,990)	$ (16,426)
10				
11	**Total**	Net Revenue Increase - Year 1	$ 53,335	$ 35,871
12		Net Revenue Increase - Year 2+	$ 68,335	$ 35,871
13				

14			OPERATING INCOME		RATE BASE	
15	Adj. No.	Adjustment Title	Company Application	Settlement Agreement	Company Application	Settlement Agreement
16			$ 119,362	$ 119,362	$ 1,733,416	$ 1,733,416
17						
18	SC1010	Annualize Retail Revenues for Current Rates	$ 43,203	$ 43,201	$ -	$ -
19	SC1020	Eliminate Unbilled Revenues	(4,334)	(4,334)	-	-
20	SC1030	Adjust Other Revenue	(394)	(394)	-	-
21	SC2010	Update Fuel Costs to Approved Rates	(43,333)	(43,349)	(5,431)	(5,431)
22	SC2030	Eliminate Cost Recovered through Non-Fuel Riders	(5,771)	(5,771)	(32,017)	(32,017)
23	SC2040	Adjust O&M for Executive Compensation	324	119	-	-
24	SC2050	Normalize O&M Labor Expenses	(124)	1,511	-	-
25	SC2060	Update Benefits Costs	(313)	(91)	-	(642)
26	SC2080	Adjust Test Year Expenses	1,732	3,220	-	-
27	SC2090	Adjust Aviation Expenses	147	147	-	-
28	SC2100	Levelize Nuclear Refueling Outage Costs	(26)	(26)	-	-
29	SC2120	Adjust Reserve for End-of-Life Nuclear Costs	1,224	1,394	-	-
30	SC3010	Annualize Depreciation on Year-End Plant Balances	(9,217)	(11,208)	(12,285)	(4,486)
31	SC3020	Annualize Property Taxes on Year-End Plant Balances	(1,005)	(1,447)	-	-
32	SC3030	Adjust for Post Test Year Additions to Plant in Service	(3,119)	-	94,746	26,877
33	SC3040	Adjust Depreciation for New Depreciation Rates		(6,882)		(9,170)
34	SC3050	Add CWIP in Rate Base	-	-	62,778	86,259
35	SC3060	Remove NCEMPA Acquistion Adjustment	867	867	(24,266)	(23,496)
36	SC3090	Amortize Roxboro Wastewater Treatment Plant Costs	(163)	(133)	(598)	-
37	SC4010	Amortize Deferred Environmental ARO Costs	(11,531)	(5,662)	69,188	33,971
38	SC5010	Remove Expiring Amortizations	4,218	4,218	(1,385)	(1,385)
39	SC5020	Amortize Rate Case Costs	(729)	(675)	1,384	(1,531)
40	SC5030	Amortize Deferred Environmental Non-ARO Costs	(3,057)	(817)	4,412	4,902
41	SC5040	Amortize Deferred Grid Costs	(6,334)	(1,224)	25,336	19,583
42	SC5080	Adjust Approved Regulatory Assets and Liabilities	(232)	(232)	-	-
43	SC5100	Amortize Deferred SC AMI Costs	(3,490)	(508)	3,783	7,111
44	SC5110	Amortize Deferred Asheville Combined Cycle Costs	(2,021)	(327)	18,189	11,756
45	SC5140	Amortized Deferred S.C. Act No. 62 Costs	(572)	(512)	(299)	(1,443)
46	SC6010	Adjust Coal Inventory	-	-	1,945	540
47	SC6020	Adjust 1/8 O&M for accounting and pro-forma adjustments	-	-	4,103	3,622
48	SC6030	Synchronize Interest Expense	1,070	885	-	-
49	SC7010	Normalize Storm Costs	(2,405)	(2,405)	-	-
50	SC7030	Adjust for Storm Reserve	(2,252)	(2,252)	(2,252)	(2,252)
51		Total Pro Forma Adjusments	$ (47,636)	$ (32,684)	$ 207,332	$ 112,768
52		Operating Income As Adjusted Before Customer Growth	71,726	86,678		
53		Customer Growth	176	212		
54		Net Operating Income for Return/Total Rate Base	$ 71,902	$ 86,891	$ 1,940,748	$ 1,846,184

Attachment A

DUKE ENERGY PROGRESS, LLC
SUMMARY OF PROPOSED REVENUE ADJUSTMENTS
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in Thousands)

Line No.	Description		SC Retail	
1	Proposed Base Rate Revenue Increase	$	52,297	[1]
2	Proposed Update to EDIT-1 Rider	$	(16,426)	[2]
3	Proposed Net Revenue Increase - Year 2+	$	35,871	
4	Removed Proposed Rate Year 1 Step-In Decrement Rider	$	-	
5	Proposed Net Revenue Increase - Year 1	$	35,871	

Notes: [1] Elliott Exhibit 1 Page 1 Settlement, Column 5, Line 1

[2] Elliott Exhibit 3 Page 3 Settlement

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Exhibit 2
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Attachment A

DUKE ENERGY PROGRESS, LLC
EXCESS DEFERED INCOME TAX RIDER REVENUE REQUIREMENT - YEAR 4 ACCELERATED
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in thousands)

Line No.	Description	Federal EDIT - Protected SC Retail (A)	Federal EDIT - Unprotected, PP&E related SC Retail (B)	Federal EDIT - Unprotected, non PP&E related SC Retail (C)	Deferred Revenue SC Retail (D)	NC EDIT SC Retail (E)	Total SC Retail (F)	
	Year 4 EDIT Rider Update:							
1	Regulatory liability including gross up for Year 3 Rider calculation	$ (131,470)	$ (52,473)	$ (4,568)	$ (6,152)	$ -	$(194,663)	[1]
2	Amortization (includes 7 months of actual and 5 months of projected)	4,956	2,915	1,523	6,152	-	15,546	[1]
3	Regulatory liability including gross up for Year 4 Rider calculation (L1 + L2)	$ (126,514)	$ (49,558)	$ (3,046)	$ -	$ -	$(179,117)	[1]
4	ARAM rate	3.24%						[1]
5	Remaining Amortization Period	26.45	17	2	-	-		[1]
6	Annual amortization amount	$ (4,956)	$ (2,915)	$ (1,523)	$ -	$ -	$ (9,394)	[1]
	Year 4 EDIT Rider Rate Case Update (effective April 1, 2023):							
7	Regulatory liability including gross up for Year 4 Rider calculation (L3)	$ (126,514)	$ (49,558)	$ (3,046)	$ -	$ -	$(179,117)	
8	Amortization (June 1, 2022 - March 31, 2023) (L2 / 12 * 10)	4,130	2,429	1,269	-	-	7,829	[2]
9	Regulatory liability including gross up as of April 1, 2023 (L7 + L8)	$ (122,384)	$ (47,129)	$ (1,777)	$ -	$ -	$(171,289)	
10	ARAM rate (L4)	3.24%						
11	Remaining Amortization Period	25.61	2.75	1.17	-	-		[3]
12	Annual Amortization amount, April 1, 2023 - May 31, 2023 (L9 / L11)	$ (4,956)	$ (17,138)	$ (1,523)	$ -	$ -	$ (23,617)	
13	**Proposed Rate Case Impact to Amortization (L12 - L6)**						**$ (14,222)**	
	Year 5 EDIT Rider Update (effective June 1, 2023)							
14	Regulatory liability including gross up as of April 1, 2023 (L9)	$ (122,384)	$ (47,129)	$ (1,777)	$ -	$ -	$(171,289)	[4]
15	Amortization amount April 1, 2023 and May 31, 2023 (-L12)	826	2,856	254	-	-	3,936	[4]
16	Regulatory liability including gross up as of June 1, 2023 (L14 + L15)	$ (121,557)	$ (44,272)	$ (1,523)	$ -	$ -	$(167,353)	[4]
17	ARAM rate	3.24%						[4]
18	Remaining Amortization Period	25.45	2.58	1.00				[3] [4]
19	Annual amortization amount	$ (4,956)	$ (17,138)	$ (1,523)	$ -	$ -	$ (23,617)	[4]

[1] Docket No. 2018-318-E, Excess Deferred Income Tax Rider (EDIT) Revenue Requirement - Year 4, Exhibit 1, Page 1, Lines 1 - 6
[2] Projected amortization from June 1, 2022 through March 31, 2023
[3] Remaining amortization period for Federal EDIT - Unprotected PP&E related reflects accelerated amortization period of 33 months
[4] The EDIT rider amounts for Year 5 are shown for illustrative purposes only. Actual rider amounts will be filed for Commission approval each year by March 31st.

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Settlement

Attachment A

DUKE ENERGY PROGRESS, LLC
EXCESS DEFERED INCOME TAX RIDER REVENUE REQUIREMENT - YEAR 4 ACCELERATED
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in thousands)

Line No.	Cost of Capital per Elliott Exhibit 1 Page 2 Settlement	Ratio	Rate	After Tax Weighted Average Cost of Capital
1	Debt	47.57%	3.77%	1.35%
2	Equity	52.43%	9.60%	5.03%
3	After Tax Weighted Average Cost of Capital			6.38%
4	SC1010-4 Tax Rate - 2022 Calculation of Tax Rates, Line 10			24.95%
5	Retention factor for Gross Receipts Taxes and PSC Utility Assessment Fee			99.48%

Annual Rider Calculation

		Amortization - From Page 1																
Line No.	Year	Beginning Balance, Page 1 (A)	Federal EDIT - Protected (B)	Federal EDIT - Unprotected, PP&E related (C)	Federal EDIT - Unprotected, non PP&E related (D)	Deferred Revenue (E)	NC EDIT (F)	Total Amortization (G) =(B)+(C)+(D)+(E)+(F)	Ending Balance before Return (H) = (A) - (G)	Average of Beginning and Ending Balance (I) = ((A) + (H)) /2	EDIT Balance in Base Rates (J)	Change in Regulatory Liability for Rider Return (K) = (I) - (J)	Return for Rider (L) = (K) x After Tax WACC	True-up for sales volume (M)	Rider Revenues (N) = (G) + (L) + (M)	Rider Revenues incl. Gross receipts taxes, Utility Assessment (N) = (M) / Retention Factor	Rider Revenues Grossed Up to Annual Amount (O) = (N) / mths in period * 12	
6	Jun 19-May 20	(219,924)	(5,432)	(2,913)	(955)	(2,987)	(1,140)	(13,425)	(206,499)	($213,212)	(222,870)	$9,658	$629	$0	(12,797)	(12,854)	(12,854)	[1]
7	Jun 20-May 21	(212,941)	(5,447)	(2,917)	(1,524)	(6,152)	(47)	(16,086)	(196,855)	($204,898)	(222,870)	$17,972	$1,170	187	(14,729)	(14,803)	(14,803)	[1]
8	Jun 21-May 22	(194,663)	(7,544)	(2,915)	(1,523)	(6,152)	-	(18,134)	(176,530)	($185,596)	(222,870)	$37,273	$2,426	(426)	(16,133)	(16,220)	(16,220)	[1]
9	Jun 22-Mar 23	(179,117)	(4,130)	(2,429)	(1,269)	-	-	(7,829)	(171,289)	($175,203)	(222,870)	$47,667	$2,586	(165)	(5,408)	(5,436)	(6,523)	[2]
10	Apr 23-May 23	(171,289)	(826)	(2,856)	(254)	-	-	(3,936)	(167,353)	($169,321)	(182,979)	$13,659	$145	-	(3,791)	(3,811)	(22,864)	[3]
11	Jun 23-May 24	(167,353)	(4,956)	(17,138)	(1,523)	-	-	(23,617)	(143,736)	($155,544)	(182,979)	$27,435	$1,750	-	(21,867)	(21,981)	(21,981)	[4]
12	Jun 24-May 25	(143,736)	(4,956)	(17,138)	-	-	-	(22,094)	(121,642)	($132,689)	(182,979)	$50,291	$3,209	-	(18,886)	(18,984)	(18,984)	[4]
13	Jun 25-Dec 25	(121,642)	(2,891)	(9,997)	-	-	-	(12,888)	(108,753)	($115,197)	(182,979)	$67,782	$2,523	-	(10,366)	(10,420)	(17,863)	[4]
14	Jan 26-May 26	(108,753)	(2,065)	-	-	-	-	(2,065)	(106,688)	($107,721)	(182,979)	$75,258	$2,001	-	(65)	(65)	(156)	[4]
15	Jun 26-May 27	(106,688)	(4,956)	-	-	-	-	(4,956)	(101,732)	($104,210)	(182,979)	$78,769	$5,025	-	69	69	69	[4]

[1] Docket No. 2018-318-E, Excess Deferred Income Tax Rider (EDIT) Revenue Requirement - Year 4, Exhibit 1, Page 2, Lines 6 - 8.
[2] Represents June 1, 2022 through March 31, 2023 based on current approved revenue requirement per Docket No. 2018-318-E, Excess Deferred Income Tax Rider (EDIT) Revenue Requirement - Year 4, Exhibit 1, Page 2, Line 9.
[3] Proposed revenue requirement effective April 1, 2023 through May 31, 2023 in order to accelerate the flow back of Federal EDIT - Unprotected PP&E to 33 months. Reflects updated EDIT Balance in Base Rates effective April 1, 2023.
[4] The rider amounts for Years 5 through 8 are shown for illustrative purposes only. Actual rider amounts will be filed for Commission approval each year by March 31st.

Elliott
Exhibit 3 Page 2
Settlement

Attachment A

DUKE ENERGY PROGRESS, LLC
EXCESS DEFERED INCOME TAX RIDER REVENUE REQUIREMENT - YEAR 4 ACCELERATED
FOR THE TEST PERIOD ENDED DECEMBER 31, 2021
DOCKET NO. 2022-254-E
(Dollars in thousands)

Line No.	Annualized Excess Deferred Income Tax (EDIT) Rider Revenue Requirements		
1	Year 4 - As Approved: June 1, 2022 - May 31, 2023	$	(6,439) [1]
2	Year 4 - As Proposed: Effective April 1, 2023	$	(22,864) [2]
3	Change in EDIT Rider Revenues Including Gross Receipts Tax and PSC Utility Assessment Fee (L2 - L1)	$	(16,426)

[1] Approved in Order No. 2022-338 (May 5, 2022) in Docket No. 2018-318-E as proposed in Exhibit 1 Page 2, Line 9 filed on March 31, 2022.

[2] Elliott Exhibit 3 Page 2 Settlement, Line 10

Elliott
Exhibit 3 Page 3
Settlement

Attachment B

DUKE ENERGY PROGRESS, LLC
PSCSC Docket No. 2022-254-E
SC RETAIL COST OF SERVICE-ADJ AT PROPOSED REV
SETTLEMENT FILING
Reed Settlement Exhibit No. 4
For the test year ending December 31, 2021
Dollars in Thousands

Spread of Proposed Base Rate Increase to Customer Classes

Line No.	Rate Class	Present Revenue Run: Annualized Rate Base (A)	Present Revenue Run: Present Rates Revenues Excluding Riders (B)	Present Revenue Run: Present Net Operating Income (C)	Present ROR (D)=(C)/(A)	Gross Revenues At Average ROR (E)	Variance From The Average (F)=(B)-(E)	Proposed Reduction in Variance from The Average (G)	Proposed Rate Increase Before Reduction in Variance (H)
1	RES	$ 977,500	$ 250,887	$ 24,172	2.47%	$ 279,979	$ (29,092)	$ 3,782	$ 27,690
2	SGS	121,354	34,646	5,535	4.56%	34,881	(235)	31	3,438
3	SGSTCLR	2,489	627	106	4.28%	642	(14)	2	71
4	MGS	377,483	146,453	28,236	7.48%	132,503	13,950	(1,814)	10,693
5	LGS	269,908	137,481	26,161	9.69%	119,550	17,931	(2,331)	7,646
6	SI	5,589	1,848	448	8.02%	1,601	247	(32)	158
7	TSS	1,303	257	(17)	-1.29%	361	(104)	14	37
8	ALS, SLS	90,184	19,805	2,231	2.47%	22,500	(2,695)	350	2,560
9	SFL	175	49	18	10.09%	37	13	(2)	5
10	SC-RETAIL	$ 1,846,184	$ 592,054	$ 86,891	4.71%	$ 592,054	$ (0)	$ 0	$ 52,297

Line No.	Rate Class	Base Rates Proposed Rate Increase After Reduction in Variance (I)=(H)+(G)	Revised Settlement Offer Base Rate Allocation Percentage (J)=(I)/(M)	33 Months Proposed Update to EDIT Rider (K)	Net of EDIT Proposed Rate Increase Effective 4/1/2023 (L)=(I)+(K)	Total Adjusted Present Rates Revenues Including Riders (M)	Revised Settlement Offer Net Increase (N) = (L) / (M)	ROR at Proposed Rates (O)	Zone of Reasonableness Percent of Average ROR (P)
1	RES	$ 31,472	11.88%	$ (8,791)	$ 22,681	$ 264,907	8.56%	4.88%	71.51%
2	SGS	3,468	9.38%	(1,090)	2,378	36,988	6.43%	6.70%	98.15%
3	SGSTCLR	72	10.59%	(22)	50	683	7.30%	6.45%	94.52%
4	MGS	8,880	5.68%	(3,258)	5,622	156,017	3.60%	9.24%	135.37%
5	LGS	5,315	3.89%	(2,273)	3,041	136,736	2.22%	11.17%	163.59%
6	SI	126	6.40%	(50)	76	1,973	3.86%	9.71%	142.24%
7	TSS	50	18.44%	(12)	38	273	14.05%	1.61%	23.55%
8	ALS, SLS	2,911	14.96%	(928)	1,983	19,456	10.19%	4.88%	71.46%
9	SFL	3	6.80%	(2)	2	49	3.51%	11.52%	168.69%
10	SC-RETAIL	$ 52,297	8.47%	$ (16,426)	$ 35,871	617,082	5.81%	6.83%	100.00%

Calculations for Rate Design in Order to Apply Increase to Unadjusted Billing Determinants

Line No.	Rate Class	Proposed Rate Increase After Reduction in Variance (Q) = (I)	Customer Growth Adjustment in Present Revenues (R)	Weather Normalization Adjustment in Present Revenues (S)	Total Adjustments to Exclude for Rate Design (T) = (R) + (S)	Ratio of Unadjusted Present Revenues to Adjusted (U) = [(B) - (T)] / (B)	Target Revenue Increase for Rate Design (to be applied to unadjusted billing determinants) (V) = (Q) x (U)
11	RES	$ 31,472	$ -	$ -	$ -	100.0%	$ 31,472
12	SGS	3,468	-	-	-	100.0%	3,468
13	SGSTCLR	72	-	-	-	100.0%	72
14	MGS	8,880	-	-	-	100.0%	8,880
15	LGS	5,315	-	-	-	100.0%	5,315
16	SI	126	-	-	-	100.0%	126
17	TSS	50	-	-	-	100.0%	50
18	ALS, SLS	2,911	-	-	-	100.0%	2,911
19	SFL	3	-	-	-	100.0%	3
20	SC-RETAIL	$ 52,297	$ -	$ -	$ -		$ 52,297

Line No.	Rate Class	Total Unadjusted EDIT Rider (W)	Revenue Increase for Rate Design Plus Sum of Additional Rider Impacts (X) = (V) + (W)	Total Unadjusted Present Rates Revenues Including Riders (Y)	Proposed Percent Increase to Unadjusted Revenues for Rate Design (Z) = (X) / (Y)	ORS Settlement Adjustments (AA)	Target Revenue Increase for Rate Design With ORS Settlement Adjustments (AB) = (X) + (AA)	Rate Design Migration Adjustments (AC)	Target Revenue Increase for Rate Design With Migration Adjustments (AD) = (X) + (AA) + (AC)
11	RES	$ (8,791)	$ 22,681	$ 264,907	8.56%	$ 408	$ 23,089	$ 460	$ 23,549
12	SGS	(1,090)	2,378	36,988	6.43%	(408)	1,970	-	1,970
13	SGSTCLR	(22)	50	683	7.30%	-	50	-	50
14	MGS	(3,258)	5,622	156,017	3.60%	-	5,622	869	6,490
15	LGS	(2,273)	3,041	136,736	2.22%	-	3,041	-	3,041
16	SI	(50)	76	1,973	3.86%	-	76	-	76
17	TSS	(12)	38	273	14.05%	-	38	-	38
18	ALS, SLS	(928)	1,983	19,456	10.19%	-	1,983	-	1,983
19	SFL	(2)	2	49	3.51%	-	2	-	2
20	SC-RETAIL	$ (16,426)	$ 35,871	$ 617,082	5.81%	$ -	$ 35,871	$ 1,329	$ 37,200

Revenue Increases with ORS Settlement Adjustments

Line No.	Rate Class	Present Revenues Including Riders: Rate Increases Without EDIT-1 Rider Change (AE) = [(V) + (AA)] / (Y)	Present Revenues Including Riders: Rate Increases With EDIT-1 Rider Change (AF) = [(X) + (AA)] / (Y)	Present Revenues Excluding Riders: Rate Increases Without EDIT-1 Rider Change (AE) = [(V) + (AA)] / (B)	Present Revenues Excluding Riders: Rate Increases With EDIT-1 Rider Change (AF) = [(X) + (AA)] / (B)
21	RES	12.03%	8.72%	12.71%	9.20%
22	SGS	8.27%	5.33%	8.83%	5.69%
23	SGSTCLR	10.59%	7.30%	11.53%	7.95%
24	MGS	5.68%	3.60%	6.06%	3.84%
25	LGS	3.89%	2.22%	3.87%	2.21%
26	SI	6.40%	3.86%	6.83%	4.13%
27	TSS	18.44%	14.05%	19.62%	14.95%
28	ALS, SLS	14.96%	10.19%	14.70%	10.01%
29	SFL	6.80%	3.51%	6.75%	3.48%
30	SC-RETAIL	8.47%	5.81%	8.83%	6.06%

Attachment C

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

Line	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	**Residential Service Schedule RES**							
2	Basic Facilities Charge	$11.78	-	$11.78	$11.78	0.0%	No change proposed	
3	Energy Charges SUMMER (July-Oct. Bills)	$0.12156	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
4	Energy Charges NONSUMMER (Nov.-June Bills) - First 800 kWh	$0.12156	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
5	Energy Charges NONSUMMER (Nov.-June Bills) - over 800 kWh	$0.11156	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
6	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
7	Energy Charges SUMMER (May-Sep Bills) (NEW TOU)	-	$0.12115	$0.13251	$0.12999	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
8	Energy Charges NONSUMMER (Oct-Apr Bills) - First 800 kWh (NEW TOU)	-	$0.12115	$0.13251	$0.12999	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
9	Energy Charges NONSUMMER (Oct-Apr Bills) - Over 800 kWh (NEW TOU)	-	$0.11115	$0.12251	$0.11999	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
10	**Residential Service Time-of-Use Schedule R-TOUD**							
11	Basic Facilities Charge	$14.63	-	$14.63	$14.63	0.0%	No change proposed	
12	Energy Charges On-peak	$0.08960	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
13	Energy Charges Off-peak	$0.07329	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
14	Demand Charges SUMMER (June-Sept Calendar)	$5.66	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
15	Demand Charges NONSUMMER (Oct.-May Calendar)	$4.35	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
16	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
17	Energy Charges Peak Energy (NEW TOU)	-	$0.15051	$0.17390	$0.17138	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
18	Energy Charges Off-peak Energy (NEW TOU)	-	$0.06968	$0.08051	$0.07799	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
19	Energy Charges Discount - Energy (NEW TOU)	-	$0.04877	$0.05636	$0.05384	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
20	Demand Charges Peak - KW (NEW TOU)	-	$1.84	$2.13	$2.13	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
21	Demand Charges Base - KW (NEW TOU)	-	$3.61	$4.18	$4.18	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
22	Demand Charges N/A - KW (NEW TOU)	-	$0.00	$0.00	$0.00	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
23	**Residential Service Solar Time-of-Use Schedule R-STOU**							
24	Basic Facilities Charge	$14.63	-	$14.63	$14.63	0.0%	No change proposed	
25	Demand Charges Non-Bypassable	$0.61	-	$0.61	$0.61	0.0%	No change proposed	
26	Demand Charges Grid Access Fee (Above 15 kW)	$3.95	-	$4.29	$4.29	8.6%	Rate adjusted to match residential rate class increase	
27	Energy Charges Critical Peak	$0.26752	-	$0.29042	$0.28790	8.6%	Rate adjusted to match residential rate class increase	
28	Energy Charges On-peak	$0.17595	-	$0.19101	$0.18849	8.6%	Rate adjusted to match residential rate class increase	
29	Energy Charges Off-peak	$0.11281	-	$0.12247	$0.11995	8.6%	Rate adjusted to match residential rate class increase	
30	Energy Charges Super Off-peak	$0.08746	-	$0.09495	$0.09243	8.6%	Rate adjusted to match residential rate class increase	
31	Customer & Distribution Energy Charges On-peak	$0.04343	-	$0.04715	$0.04463	8.6%	Rate adjusted to match residential rate class increase	
32	Customer & Distribution Energy Charges Off-peak	$0.03703	-	$0.04020	$0.03768	8.6%	Rate adjusted to match residential rate class increase	
33	Customer & Distribution Energy Charges Super Off-peak	$0.03329	-	$0.03614	$0.03362	8.6%	Rate adjusted to match residential rate class increase	
34	**Small General Service Schedule SGS**							
35	Basic Facilities Charge	$12.34	-	$14.00	$14.00	13.5%	Rate adjusted to better reflect Cost of Service study findings	
36	Energy Charges BLOCK 1 - FIRST 2,000 KWH	$0.14155	-	$0.14714	$0.14199	3.9%	Rate adjusted to recover revenue requirement	
37	Energy Charges BLOCK 2 - ADDITIONAL KWH	$0.10496	-	$0.10911	$0.10396	3.9%	Rate adjusted to recover revenue requirement	
38	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
39	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
40	**General Service Schedule GS (15% higher increase than SGS)**							
41	Basic Facilities Charge ALL	$12.34	-	$14.00	$14.00	13.5%	Rate adjusted to better reflect Cost of Service study findings, matches SGS	
42	Energy Charges BLOCK 1 - First 750 kWh (Demand Extender)	$0.15006	-	$0.17850	$0.17335	19.0%	Rate adjusted to recover revenue requirement	
43	Energy Charges BLOCK 2 - Next 2,000 kWh	$0.10757	-	$0.12796	$0.12281	19.0%	Rate adjusted to recover revenue requirement	
44	Energy Charges BLOCK 3 - Additional kWh	$0.09821	-	$0.11682	$0.11167	19.0%	Rate adjusted to recover revenue requirement	
45	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
46	Energy Charges Minimum Bill	$0.05817	-	$0.05817	$0.05302	0.0%	No change proposed	
47	Demand Charges Minimum Bill	$3.03	-	$3.04	$3.04	0.3%	Rate adjusted to recover revenue requirement	
48	Billed kVAR ALL	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
49	**Small General Service Constant Load Schedule SGS-CLR**							
50	Basic Facilities Charge	$11.31	-	$14.00	$14.00	23.8%	Rate adjusted to better reflect Cost of Service study findings	
51	Energy Charges	$0.09629	-	$0.09976	$0.09396	3.6%	Rate adjusted to recover revenue requirement	
52	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
53	**Medium General Service Schedule MGS**							
54	Basic Facilities Charge	$21.35	-	$24.00	$24.00	12.4%	Rate adjusted to better reflect Cost of Service study findings	
55	Energy Charges	$0.08682	-	$0.09029	$0.08204	4.0%	Rate adjusted to recover revenue requirement	
56	Demand Charges	$6.90	-	$7.19	$7.19	4.2%	Rate adjusted to recover revenue requirement	
57	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
58	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
59	**Small General Service Time of Use Schedule SGS-TOU**							
60	Basic Facilities Charge	$27.85	-	$33.00	$33.00	18.5%	Rate adjusted to better reflect Cost of Service study findings	
61	Energy Charges On-peak (SUMMER)	$0.07734	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
62	Energy Charges On-peak (NON-SUMMER)	$0.07734	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
63	Energy Charges Off-peak	$0.06310	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
64	Demand Charges SUMMER (June-Sept Calendar)	$12.45	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
65	Demand Charges NONSUMMER (Oct.-May Calendar)	$9.85	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
66	Demand Charges Off-peak Excess	$3.04	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
67	Energy Charges Minimum Bill - On-peak	$0.05240	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
68	Energy Charges Minimum Bill - Off-peak	$0.05240	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
69	Demand Charges Minimum Bill	$3.03	-	$0.00	$0.00	-100.0%	Rate being replaced with new TOU rate structure shown below	
70	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	Changed methodology to capture kVAR in demand (kW) to be consistent with DEC	
71	Energy Charges Peak - Summer (NEW TOU)	-	$0.13937	$0.14053	$0.13228	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
72	Energy Charges Off-Peak - Summer (NEW TOU)	-	$0.06222	$0.06409	$0.05584	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
73	Energy Charges Super Off-Peak Summer (NEW TOU)	-	$0.03920	$0.04038	$0.03213	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
74	Energy Charges Peak - Winter (NEW TOU)	-	$0.13937	$0.14053	$0.13228	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
75	Energy Charges Off-Peak - Winter (NEW TOU)	-	$0.06222	$0.06409	$0.05584	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
76	Energy Charges Super Off-Peak Winter (NEW TOU)	-	$0.03920	$0.04038	$0.03213	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
77	Demand Charges Peak - Summer (NEW TOU)	-	$3.38	$3.60	$3.60	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
78	Demand Charges Mid - Summer (NEW TOU)	-	$7.42	$7.90	$7.90	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
79	Demand Charges Base - Summer (NEW TOU)	-	$1.09	$1.16	$1.16	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
80	Demand Charges Peak - Winter (NEW TOU)	-	$3.38	$3.60	$3.60	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
81	Demand Charges Mid - Winter (NEW TOU)	-	$7.42	$7.90	$7.90	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
82	Demand Charges Base - Winter (NEW TOU)	-	$1.09	$1.16	$1.16	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
83	**Small General Service Thermal Energy Storage Schedule SGS-TES**							
84	Basic Facilities Charge ALL	$27.85	-	$0.00		-100.0%	Rate Schedule being terminated	
85	Energy Charges On-peak	$0.06443	-	$0.00000		-100.0%	Rate Schedule being terminated	
86	Energy Charges Off-peak	$0.06216	-	$0.00000		-100.0%	Rate Schedule being terminated	
87	Demand Charges SUMMER (June-Sept Calendar)	$14.70	-	$0.00		-100.0%	Rate Schedule being terminated	
88	Demand Charges NONSUMMER (Oct.-May Calendar)	$12.08	-	$0.00		-100.0%	Rate Schedule being terminated	
89	Demand Charges Off-peak Excess	$3.03	-	$0.00		-100.0%	Rate Schedule being terminated	
90	Energy Charges Minimum Bill	$0.05240	-	$0.00000		-100.0%	Rate Schedule being terminated	
91	Demand Charges Minimum Bill	$3.03	-	$0.00		-100.0%	Rate Schedule being terminated	
92	Billed kVAR ALL	$0.30	-	$0.00		-100.0%	Rate Schedule being terminated	
93	**Church and School Service Schedule CSE (targets a 15% higher increase for CSE/CSG to incent migration from frozen tariff)**							
94	Basic Facilities Charge ALL	$21.35	-	$24.00	$24.00	12.4%	Rate adjusted to better reflect Cost of Service study findings, matches MGS	
95	Energy Charges ALL	$0.13062	-	$0.15544	$0.14719	19.0%	Rate adjusted to recover revenue requirement	
96	Three Phase Charge ALL	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
97	Energy Charges Minimum Bill	$0.05731	-	$0.05731	$0.04906	0.0%	No change proposed	
98	Demand Charges Minimum Bill	$3.03	-	$3.04	$3.04	0.3%	Rate adjusted to recover revenue requirement	
99	Billed kVAR ALL	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
100	**Church and School Service Schedule CSG (targets a 15% higher increase for CSE/CSG to incent migration from frozen tariff)**							
101	Basic Facilities Charge ALL	$21.35	-	$24.00	$24.00	12.4%	Rate adjusted to better reflect Cost of Service study findings, matches MGS	
102	Energy Charges ALL	$0.13062	-	$0.15544	$0.14719	19.0%	Rate adjusted to recover revenue requirement	
103	Three Phase Charge ALL	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
104	Energy Charges Minimum Bill	$0.05731	-	$0.05731	$0.04906	0.0%	No change proposed	
105	Demand Charges Minimum Bill	$3.03	-	$3.04	$3.04	0.3%	Rate adjusted to recover revenue requirement	
106	Billed kVAR ALL	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
107	**Traffic Signal Service Schedule TFS**							
108	Basic Facilities Charge	$12.34	-	$14.00	$14.00	13.5%	Rate adjusted to recover revenue requirement; matches SGS	
109	Energy Charges	$0.09190	-	$0.10490	$0.10285	14.1%	Rate adjusted to recover revenue requirement	
110	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
111	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	

Attachment C

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
112	**Sports Field Lighting Service Schedule SFLS**							
113	Basic Facilities Charge	$21.35	-	$24.00	$24.00	12.4%	Rate adjusted to better reflect Cost of Service study findings, matches MGS	
114	Energy Charges	$0.07381	-	$0.07584	$0.09034	2.8%	Rate adjusted to recover revenue requirement	
115	Demand Charges	$1.22	-	$1.25	$1.25	2.5%	Rate adjusted to recover revenue requirement	
116	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
117	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	Changed methodology to capture kVAR in demand (kW) to be consistent with DEC	
118	Disconnect/Connect Charge	$17.00	-	$8.00	$8.00	-52.9%	Rate adjusted to match proposed connect/disconnect charges in the Service Regulations	
119	**Seasonal and Intermittent Service Schedule SI**							
120	Basic Facilities Charge	$21.35	-	$24.00	$24.00	12.4%	Rate adjusted to better reflect Cost of Service study findings, matches MGS	
121	Energy Charges BLOCK 1 - FIRST 2,000 KWH	$0.16113	-	$0.16693	$0.16061	3.6%	Rate adjusted to recover revenue requirement	
122	Energy Charges BLOCK 2 - ADDITIONAL KWH	$0.12192	-	$0.12631	$0.11999	3.6%	Rate adjusted to recover revenue requirement	
123	Three Phase Charge	$6.50	-	$9.00	$9.00	38.5%	Charge increased to reflect cost (See three-phase service study)	
124	Customer Seasonal Charge	$40.10	-	$45.08	$45.08	12.4%	Rate adjusted by same 12.41% as MGS Basic Customer Charge per SI Cost Study	
125	Facilities Charge	$1.72	-	$1.70	$1.70	-1.2%	Rate adjusted according to SI Cost Study	
126	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
127	**Large General Service Schedule LGS**							
128	Basic Customer Charge	$192.00	-	$200.00	$200.00	4.2%	Rate adjusted to better reflect Cost of Service study findings	
129	Energy Charges	$0.06610	-	$0.06749	$0.05781	2.1%	Rate adjusted to recover revenue requirement	
130	Demand Charges BLOCK 1 - FIRST 5,000 KW	$13.92	-	$14.22	$14.22	2.2%	Rate adjusted to recover revenue requirement	
131	Demand Charges BLOCK 2 - NEXT 5,000 KW	$12.92	-	$13.22	$13.22	2.3%	Rate adjusted to recover revenue requirement	
132	Demand Charges BLOCK 3 - ABOVE 10,000 KW	$11.92	-	$12.22	$12.22	2.5%	Rate adjusted to recover revenue requirement	
133	Transformation Discount Transmission Demand	($0.50)	-	($0.92)	($0.92)	84.0%	Rate adjusted to reflect unit cost study	
134	Transformation Discount Transmission Energy	($0.00023)	-	($0.00023)	($0.00023)	0.0%	No change proposed	
135	Transformation Discount Distribution Demand	($0.40)	-	($0.35)	($0.35)	-12.5%	Rate adjusted to reflect unit cost study	
136	Transformation Discount Distribution Energy	($0.00002)	-	($0.00009)	($0.00009)	350.0%	Rate adjusted to reflect unit cost study	
137	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
138	**Large General Service Time of Use Schedule LGS-TOU**							
139	Basic Customer Charge	$192.00	-	$200.00	$200.00	4.2%	Rate adjusted to better reflect Cost of Service study findings, matches LGS	
140	Energy Charges On-peak	$0.06403	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
141	Energy Charges Off-peak	$0.05903	-	$0.00000		-100.0%	Rate being replaced with new TOU rate structure shown below	
142	Demand Charges SUMMER (J-S) BLOCK 1 - FIRST 5,000 KW	$21.06	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
143	Demand Charges SUMMER (J-S) BLOCK 2 - NEXT 5,000 KW	$20.06	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
144	Demand Charges SUMMER (J-S) BLOCK 3 - ABOVE 10,000 KW	$19.06	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
145	Demand Charges NONSUMMER (O-M) BLOCK 1 - FIRST 5,000 KW	$15.80	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
146	Demand Charges NONSUMMER (O-M) BLOCK 2 - NEXT 5,000 KW	$14.80	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
147	Demand Charges NONSUMMER (O-M) BLOCK 3 - ABOVE 10,000 KW	$13.80	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
148	Demand Charges Off-peak Excess	$1.31	-	$0.00		-100.0%	Rate being replaced with new TOU rate structure shown below	
149	Transformation Discount Transmission Demand	($0.50)	-	($0.92)	($0.92)	84.0%	Rate adjusted to reflect unit cost study	
150	Transformation Discount Transmission Energy	($0.00023)	-	($0.00023)	($0.00023)	0.0%	No change proposed	
151	Transformation Discount Distribution Demand	($0.40)	-	($0.35)	($0.35)	-12.5%	Rate adjusted to reflect unit cost study	
152	Transformation Discount Distribution Energy	($0.00002)	-	($0.00009)	($0.00009)	350.0%	Rate adjusted to reflect unit cost study	
153	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
154	Energy Charges Peak - Summer (NEW TOU)	-	$0.12051	$0.08079	$0.07111	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
155	Energy Charges Off-Peak - Summer (NEW TOU)	-	$0.05605	$0.05990	$0.05022	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
156	Energy Charges Super Off-Peak Summer (NEW TOU)	-	$0.03419	$0.03959	$0.02991	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
157	Energy Charges Peak - Winter (NEW TOU)	-	$0.12051	$0.08079	$0.07111	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
158	Energy Charges Off-Peak - Winter (NEW TOU)	-	$0.05605	$0.05990	$0.05022	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
159	Energy Charges Super Off-Peak Winter (NEW TOU)	-	$0.03419	$0.03959	$0.02991	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
160	Demand Charges Peak - Summer (NEW TOU)	-	$5.73	$6.12	$6.12	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
161	Demand Charges Mid - Summer First 5,000KW (NEW TOU)	-	$13.64	$14.58	$14.58	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
162	Demand Charges Mid - Summer Second 5,000KW (NEW TOU)	-	$12.96	$13.85	$13.85	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
163	Demand Charges Mid - Summer All over 5,000KW (NEW TOU)	-	$12.28	$13.12	$13.12	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
164	Demand Charges Base - Summer (NEW TOU)	-	$1.13	$1.21	$1.21	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
165	Demand Charges Peak - Winter (NEW TOU)	-	$5.73	$6.12	$6.12	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
166	Demand Charges Mid - Winter First 5,000KW (NEW TOU)	-	$13.64	$14.58	$14.58	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
167	Demand Charges Mid - Winter Second 5,000KW (NEW TOU)	-	$12.96	$13.85	$13.85	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
168	Demand Charges Mid - Winter All over 5,000KW (NEW TOU)	-	$12.28	$13.12	$13.12	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	
169	Demand Charges Base - Winter (NEW TOU)	-	$1.13	$1.21	$1.21	0.0%	Rate adjusted from the Current Equivalent** to recover revenue requirement	

Attachment C

Reed Settlement Exhibit No. 3
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Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
170	Large General Service Curtailable Time of Use Schedule LGS-CUR-TOU							
171	Basic Facilities Charge	$484.83	-	$490.16	$490.16	1.1%	Rate adjusted to better reflect Cost of Service study findings	
172	Energy Charges On-peak	$0.05954	-	$0.06019	$0.05051	1.1%	Rate adjusted to recover revenue requirement	
173	Energy Charges Off-peak	$0.05381	-	$0.05440	$0.04472	1.1%	Rate adjusted to recover revenue requirement	
174	Demand Charges SUMMER (J-S) BLOCK 1 - FIRST 5,000 KW	$22.87	-	$23.12	$23.12	1.1%	Rate adjusted to recover revenue requirement	
175	Demand Charges SUMMER (J-S) BLOCK 2 - NEXT 5,000 KW	$21.73	-	$21.97	$21.97	1.1%	Rate adjusted to recover revenue requirement	
176	Demand Charges SUMMER (J-S) BLOCK 3 - ABOVE 10,000 KW	$20.59	-	$20.82	$20.82	1.1%	Rate adjusted to recover revenue requirement	
177	Demand Charges NONSUMMER (O-M) BLOCK 1 - FIRST 5,000 KW	$17.13	-	$17.32	$17.32	1.1%	Rate adjusted to recover revenue requirement	
178	Demand Charges NONSUMMER (O-M) BLOCK 2 - NEXT 5,000 KW	$15.99	-	$16.17	$16.17	1.1%	Rate adjusted to recover revenue requirement	
179	Demand Charges NONSUMMER (O-M) BLOCK 3 - ABOVE 10,000 KW	$14.85	-	$15.01	$15.01	1.1%	Rate adjusted to recover revenue requirement	
180	Demand Charges Curtailable Billing Demand	$1.71	-	$1.73	$1.73	1.2%	Rate adjusted to recover revenue requirement	
181	Transformation Discount Transmission Demand	($0.50)	-	($0.92)	($0.92)	84.0%	Rate adjusted to reflect unit cost study	
182	Transformation Discount Transmission Energy	($0.00023)	-	($0.00023)	($0.00023)	0.0%	No change proposed	
183	Transformation Discount Distribution Demand	($0.40)	-	($0.35)	($0.35)	-12.5%	Rate adjusted to reflect unit cost study	
184	Transformation Discount Distribution Energy	($0.00002)	-	($0.00009)	($0.00009)	350.0%	Rate adjusted to reflect unit cost study	
185	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
186	Large General Service Real Time Pricing Schedule LGS-RTP							
187	RTP Administrative Charge	$160.00	-	$160.00	$160.00	0.0%	No change proposed	
188	Facilities Demand - Transmission Line	$1.30	-	$2.98	$2.98	129.2%	Rate adjusted to reflect unit cost study	
189	Facilities Demand - T/D Substation	$1.79	-	$3.97	$3.97	121.8%	Rate adjusted to reflect unit cost study	
190	Facilities Demand - Distribution Primary	$2.54	-	$5.79	$5.79	128.0%	Rate adjusted to reflect unit cost study	
191	Facilities Demand - Distribution Transformer	$2.94	-	$6.17	$6.17	109.9%	Rate adjusted to reflect unit cost study	
192	Tax Factor	0.52%	-	0.52%	0.52%	0.0%	No change proposed; Rate reflects 0.3% gross receipts tax and current 0.2202638088% SC Regulatory Fee	
193	Variable Environmental Charge (Fuel Adjustment)	$1.62	-	$1.46	$1.46	-9.9%	Matches last fuel filing	
194	Traffic Signal Service Schedule TSS							kWh
195	70 Watt-16 HR/1 Lamp BLINKER	$2.22	-	$2.53	$2.49	14.0%	All rates adjusted by the same percentage to recover revenue requirement	19
196	150 Watt-16 HR/1 Lamp BLINKER	$4.40	-	$5.02	$4.95	14.1%	Rate adjusted to recover revenue requirement	33
197	70 Watt-24 HR/1 Lamp BLINKER	$3.19	-	$3.64	$3.58	14.1%	Rate adjusted to recover revenue requirement	28
198	150 Watt-24 HR/1 Lamp BLINKER	$6.02	-	$6.87	$6.77	14.1%	Rate adjusted to recover revenue requirement	49
199	70 Watt-16 HR/1 Lamp	$3.05	-	$3.48	$3.41	14.1%	Rate adjusted to recover revenue requirement	35
200	70 Watt-16 HR/2 Lamp	$3.72	-	$4.25	$4.18	14.2%	Rate adjusted to recover revenue requirement	35
201	70 Watt-16 HR/3 Lamp	$4.07	-	$4.65	$4.58	14.3%	Rate adjusted to recover revenue requirement	35
202	70 Watt-16 HR/4 Lamp	$5.29	-	$6.04	$5.94	14.2%	Rate adjusted to recover revenue requirement	50
203	70 Watt-16 HR/5 Lamp	$4.07	-	$4.65	$4.58	14.3%	Rate adjusted to recover revenue requirement	35
204	150 Watt-16 HR/1 Lamp	$6.38	-	$7.28	$7.15	14.1%	Rate adjusted to recover revenue requirement	62
205	150 Watt-16 HR/2 Lamp	$7.83	-	$8.94	$8.81	14.2%	Rate adjusted to recover revenue requirement	62
206	150 Watt-16 HR/3 Lamp	$8.00	-	$9.13	$9.00	14.1%	Rate adjusted to recover revenue requirement	62
207	150 Watt-16 HR/4 Lamp	$11.18	-	$12.76	$12.57	14.1%	Rate adjusted to recover revenue requirement	91
208	150 Watt-16 HR/5 Lamp	$8.00	-	$9.13	$9.00	14.1%	Rate adjusted to recover revenue requirement	62
209	70 Watt-24 HR/1 Lamp	$4.25	-	$4.85	$4.75	14.1%	Rate adjusted to recover revenue requirement	51
210	70 Watt-24 HR/2 Lamp	$5.18	-	$5.91	$5.81	14.1%	Rate adjusted to recover revenue requirement	51
211	70 Watt-24 HR/3 Lamp	$5.46	-	$6.23	$6.13	14.1%	Rate adjusted to recover revenue requirement	51
212	70 Watt-24 HR/4 Lamp	$7.19	-	$8.21	$8.06	14.2%	Rate adjusted to recover revenue requirement	75
213	70 Watt-24 HR/5 Lamp	$5.46	-	$6.23	$6.13	14.1%	Rate adjusted to recover revenue requirement	51
214	150 Watt-24 HR/1 Lamp	$9.16	-	$10.46	$10.27	14.2%	Rate adjusted to recover revenue requirement	92
215	150 Watt-24 HR/2 Lamp	$10.84	-	$12.37	$12.18	14.1%	Rate adjusted to recover revenue requirement	92
216	150 Watt-24 HR/3 Lamp	$11.24	-	$12.83	$12.64	14.1%	Rate adjusted to recover revenue requirement	92
217	150 Watt-24 HR/4 Lamp	$15.50	-	$17.69	$17.41	14.1%	Rate adjusted to recover revenue requirement	135
218	150 Watt-24 HR/5 Lamp	$11.24	-	$12.83	$12.64	14.1%	Rate adjusted to recover revenue requirement	92
219	Minimum Bill	$12.34	-	$14.00	$14.00	13.5%	Matches SGS, rate adjusted to better match Cost of Service study	
220	120 watt/16 Hour Rate Adder	$1.10	-	$1.36	$1.34	13.7%	Rate adjusted to recover revenue requirement	11
221	120 watt/24 Hour Rate Adder	$1.40	-	$1.73	$1.70	14.2%	Rate adjusted to recover revenue requirement	16

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222	Street Lighting Service Schedule SLS (Targets higher increase than ALS due to much lower return)							kWh
223	9,500 Lumen SV	$10.75	-	$11.69	$12.49	8.7%	Rate adjusted to recover revenue requirement; matches ALS	46
224	16,000 Lumen SV	$12.87	-	$13.99	$15.02	8.7%	Rate adjusted to recover revenue requirement; matches ALS	59
225	28,500 Lumen SV	$16.97	-	$18.45	$20.36	8.7%	Rate adjusted to recover revenue requirement; matches ALS	109
226	50,000 Lumen SV	$21.30	-	$23.15	$25.81	8.7%	Rate adjusted to recover revenue requirement; matches ALS	152
227	9,000 Lumen MH	$13.38	-	$14.54	$15.26	8.7%	Rate adjusted to recover revenue requirement; matches ALS	41
228	20,000 Lumen MH	$18.94	-	$20.59	$22.23	8.7%	Rate adjusted to recover revenue requirement; matches ALS	94
229	33,000 Lumen MH	$24.11	-	$26.21	$28.54	8.7%	Rate adjusted to recover revenue requirement; matches ALS	133
230	110,000 Lumen MH	$47.90	-	$52.07	$58.54	8.7%	Rate adjusted to recover revenue requirement; matches ALS	370
231	5,800 Lumen SV	$7.03	-	$7.64	$8.15	8.7%	Rate adjusted to recover revenue requirement; matches ALS	29
232	7,000 Lumen MV Semi-Enclosed	$8.06	-	$8.76	$9.97	8.7%	Rate adjusted to recover revenue requirement; matches ALS	68
233	7,000 Lumen MV	$9.59	-	$10.42	$11.63	8.7%	Rate adjusted to recover revenue requirement; matches ALS	69
234	12,000 Lumen RSV	$12.13	-	$13.19	$14.22	8.7%	Rate adjusted to recover revenue requirement; matches ALS	59
235	21,000 Lumen MV	$14.44	-	$15.70	$18.31	8.7%	Rate adjusted to recover revenue requirement; matches ALS	149
236	22,000 Lumen SV	$13.68	-	$14.87	$16.37	8.7%	Rate adjusted to recover revenue requirement; matches ALS	86
237	38,000 Lumen RSV	$16.23	-	$17.64	$20.00	8.7%	Rate adjusted to recover revenue requirement; matches ALS	135
238	40,000 Lumen MH	$24.95	-	$27.12	$29.92	8.7%	Rate adjusted to recover revenue requirement; matches ALS	160
239	60,000 Lumen MV	$27.99	-	$30.43	$37.11	8.7%	Rate adjusted to recover revenue requirement; matches ALS	382
240	LED 50	$9.62	-	$10.46	$10.77	8.7%	Rate adjusted to recover revenue requirement; matches ALS	18
241	LED 75	$9.89	-	$10.75	$11.19	8.7%	Rate adjusted to recover revenue requirement; matches ALS	25
242	LED 105	$11.51	-	$12.51	$13.12	8.7%	Rate adjusted to recover revenue requirement; matches ALS	35
243	LED 150	$15.09	-	$16.40	$17.34	8.7%	Rate adjusted to recover revenue requirement; matches ALS	54
244	LED 215	$18.75	-	$20.38	$21.66	8.7%	Rate adjusted to recover revenue requirement; matches ALS	73
245	LED 280	$22.18	-	$24.11	$25.88	8.7%	Rate adjusted to recover revenue requirement; matches ALS	101
246	LED 420	$54.89	-	$59.67	$62.15	8.7%	Rate adjusted to recover revenue requirement; matches ALS	142
247	LED 530	$66.67	-	$72.47	$75.60	8.7%	Rate adjusted to recover revenue requirement; matches ALS	179
248	LED 75 (Standard Offer)	$7.60	-	$8.26	$8.70	8.7%	Rate adjusted to recover revenue requirement; matches ALS	25
249	LED 105 (Standard Offer)	$10.83	-	$11.77	$12.38	8.7%	Rate adjusted to recover revenue requirement; matches ALS	35
250	LED 215 (Standard Offer)	$16.23	-	$17.64	$18.92	8.7%	Rate adjusted to recover revenue requirement; matches ALS	73
251	LED 205 Site Lighter (Standard Offer)	$16.23	-	$17.64	$18.85	8.7%	Rate adjusted to recover revenue requirement; matches ALS	69
252	LED 75 Customer Owned	$5.55	-	$6.03	$6.47	8.6%	Rate adjusted to recover revenue requirement	25
253	LED 105 Customer Owned	$5.93	-	$6.45	$7.06	8.8%	Rate adjusted to recover revenue requirement	35
254	LED 215 Customer Owned	$7.38	-	$8.02	$9.30	8.7%	Rate adjusted to recover revenue requirement	73
255	LED 205 Customer Owned Site Lighter	$7.24	-	$7.87	$9.08	8.7%	Rate adjusted to recover revenue requirement	69
256	Monthly UG Charge	$3.90	-	$4.24	$4.24	8.7%	Rate adjusted to recover revenue requirement, matches ALS	
257	One-Time UG Charge	$518.00	-	$600.00	$600.00	15.8%	Rate adjusted to match approximate underground trenching work order costs, matches ALS	
258	Wood Pole	$1.68	-	$2.06	$2.06	22.6%	Rate adjusted to recover revenue requirement	
259	Metal, Fiberglass or Post Pole	$3.37	-	$4.13	$4.13	22.6%	Rate adjusted to recover revenue requirement	
260	12-Foot Smooth Concrete Post	$12.03	-	$14.74	$14.74	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
261	Decorative Square Metal	$15.76	-	$20.80	$20.80	22.5%	Rate adjusted to recover revenue requirement	
262	16-Foot Smooth Concrete Post	$13.24	-	$16.22	$16.22	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
263	13-Foot Fluted Concrete Post	$18.05	-	$22.11	$22.11	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
264	Decorative Aluminum 12-Foot Post	$21.66	-	$26.53	$26.53	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
265	Decorative 35- or 39-Foot Tapered Metal Pole	$34.40	-	$42.14	$42.14	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
266	System Metal Pole	$1.08	-	$1.32	$1.32	22.2%	Rate adjusted to recover revenue requirement	
267	Masterpiece Series A 12-Foot Decorative Post	$21.66	-	$26.53	$26.53	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
268	Masterpiece Series A 16-Foot Decorative Post	$26.47	-	$32.43	$32.43	22.5%	Rate adjusted to recover revenue requirement, matches ALS	
269	Masterpiece Series A Twin Mounting Bracket	$5.00	-	$5.00	$5.00	0.0%	No change proposed	
270	Masterpiece Series A Adder	$3.00	-	$3.25	$3.25	8.3%	Rate adjusted to recover revenue requirement, matches ALS	
271	Masterpiece Series B Adder	$4.15	-	$4.50	$4.50	8.4%	Rate adjusted to recover revenue requirement, matches ALS	

Attachment C

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
272	Street Lighting Service (Residential Subdivisions and Neighborhoods) Schedule SLR							kWh
273	OH/1 light per 10 customers/7,000 Lumen MV	$1.39	-	$1.63	$1.73	17.3%	Rate adjusted to recover revenue requirement	5.75
274	OH/1 light per 10 customers/9,500 Lumen SV	$1.39	-	$1.63	$1.73	17.3%	Rate adjusted to recover revenue requirement	5.75
275	OH/1 light per 10 customers/LED 50	$1.40	-	$1.65	$1.68	17.9%	Rate adjusted to recover revenue requirement	1.8
276	OH/1 light per 10 customers/12,000 Lumen SV	$1.52	-	$1.78	$1.88	17.1%	Rate adjusted to recover revenue requirement	5.6
277	OH/1 light per 5 customers/7,000 Lumen MV	$2.74	-	$3.22	$3.42	17.5%	Rate adjusted to recover revenue requirement	11.50
278	OH/1 light per 5 customers/9,500 Lumen SV	$2.74	-	$3.22	$3.42	17.5%	Rate adjusted to recover revenue requirement	11.50
279	OH/1 light per 5 customers/LED 50	$2.72	-	$3.20	$3.26	17.6%	Rate adjusted to recover revenue requirement	3.60
280	OH/1 light per 5 customers/12,000 Lumen SV	$3.04	-	$3.57	$3.77	17.4%	Rate adjusted to recover revenue requirement	11.2
281	OH/1 light per 3 customers/7,000 Lumen MV	$4.55	-	$5.35	$5.69	17.6%	Rate adjusted to recover revenue requirement	19.17
282	OH/1 light per 3 customers/9,500 Lumen SV	$4.55	-	$5.35	$5.69	17.6%	Rate adjusted to recover revenue requirement	19.17
283	OH/1 light per 3 customers/LED 50	$4.57	-	$5.37	$5.47	17.5%	Rate adjusted to recover revenue requirement	6
284	UG/1 light per 10 customers on wood pole 7,000 lumen	$2.04	-	$2.40	$2.50	17.6%	Rate adjusted to recover revenue requirement	5.75
285	UG/1 light per 10 customers on wood pole 9,500 lumen	$2.04	-	$2.40	$2.50	17.6%	Rate adjusted to recover revenue requirement	5.75
286	UG/1 light per 10 customers on wood pole LED 50	$2.04	-	$2.40	$2.43	17.6%	Rate adjusted to recover revenue requirement	1.8
287	UG/1 light per 10 customers on wood pole 12,000 lumen	$2.17	-	$2.55	$2.65	17.5%	Rate adjusted to recover revenue requirement	5.6
288	UG/1 light per 5 customers on wood pole 7,000 lumen	$4.06	-	$4.77	$4.97	17.5%	Rate adjusted to recover revenue requirement	11.50
289	UG/1 light per 5 customers on wood pole 9,500 lumen	$4.06	-	$4.77	$4.97	17.5%	Rate adjusted to recover revenue requirement	11.50
290	UG/1 light per 5 customers on wood pole LED 50	$4.04	-	$4.75	$4.81	17.6%	Rate adjusted to recover revenue requirement	3.60
291	UG/1 light per 5 customers on wood pole 12,000 lumen	$4.36	-	$5.12	$5.32	17.4%	Rate adjusted to recover revenue requirement	11.2
292	UG/1 light per 3 customers on wood pole 7,000 lumen	$6.76	-	$7.94	$8.28	17.5%	Rate adjusted to recover revenue requirement	19.17
293	UG/1 light per 3 customers on wood pole 9,500 lumen	$6.76	-	$7.94	$8.28	17.5%	Rate adjusted to recover revenue requirement	19.17
294	UG/1 light per 3 customers on wood pole LED 50	$6.78	-	$7.97	$8.07	17.6%	Rate adjusted to recover revenue requirement	6
295	UG/1 light per 10 customers on fiberglass/metal pole or post 7,000 lumen	$2.22	-	$2.61	$2.71	17.6%	Rate adjusted to recover revenue requirement	5.75
296	UG/1 light per 10 customers on fiberglass/metal pole or post 9,500 lumen	$2.22	-	$2.61	$2.71	17.6%	Rate adjusted to recover revenue requirement	5.75
297	UG/1 light per 10 customers on fiberglass/metal pole or post LED 50	$2.23	-	$2.62	$2.65	17.5%	Rate adjusted to recover revenue requirement	1.8
298	UG/1 light per 10 customers on fiberglass/metal pole or post LED 50 Post-Top	$2.97	-	$3.49	$3.52	17.5%	Rate adjusted to recover revenue requirement	1.8
299	UG/1 light per 10 customers on fiberglass/metal pole or post 12,000 lumen	$2.35	-	$2.76	$2.86	17.4%	Rate adjusted to recover revenue requirement	5.6
300	UG/1 light per 6 customers on fiberglass/metal/pole or post 7,000 lumen	$3.65	-	$4.29	$4.46	17.5%	Rate adjusted to recover revenue requirement	9.58
301	UG/1 light per 6 customers on fiberglass/metal/pole or post 9,500 lumen	$3.65	-	$4.29	$4.46	17.5%	Rate adjusted to recover revenue requirement	9.58
302	UG/1 light per 6 customers on fiberglass/metal/pole or post LED 50	$3.64	-	$4.28	$4.33	17.6%	Rate adjusted to recover revenue requirement	3
303	UG/1 light per 6 customers on fiberglass/metal/pole or post LED 50 Post-Top	$4.85	-	$5.70	$5.75	17.5%	Rate adjusted to recover revenue requirement	3
304	UG/1 light per 6 customers on fiberglass/metal/pole or post 12,000 lumen	$3.88	-	$4.56	$4.72	17.5%	Rate adjusted to recover revenue requirement	9.33
305	UG/1 light per 3 customers on fiberglass/metal/pole or post 7,000 lumen	$7.36	-	$8.65	$8.99	17.5%	Rate adjusted to recover revenue requirement	19.17
306	UG/1 light per 3 customers on fiberglass/metal/pole or post 9,500 lumen	$7.36	-	$8.65	$8.99	17.5%	Rate adjusted to recover revenue requirement	19.17
307	UG/1 light per 3 customers on fiberglass/metal/pole or post LED 50	$7.38	-	$8.67	$8.77	17.5%	Rate adjusted to recover revenue requirement	6
308	UG/1 light per 3 customers on fiberglass/metal/pole or post LED 50 Post-Top	$9.84	-	$11.56	$11.66	17.5%	Rate adjusted to recover revenue requirement	6
309	12,000 lumen retrofit adder - 1 per 10	$0.13	-	$0.15	$0.15	15.4%	Rate adjusted to recover revenue requirement	
310	12,000 lumen retrofit adder - 1 per 5	$0.30	-	$0.35	$0.35	16.7%	Rate adjusted to recover revenue requirement	
311	12,000 lumen retrofit adder - 1 per 6	$0.23	-	$0.27	$0.27	17.4%	Rate adjusted to recover revenue requirement	
312	UG Only Charge/1 light per 10 customers on wood pole 7,000/12,000 lumen	$0.36	-	$0.42	$0.42	16.7%	Rate adjusted to recover revenue requirement	
313	UG Only Charge/1 light per 5 customers on wood pole 7,000/12,000 lumen	$0.67	-	$0.79	$0.79	17.9%	Rate adjusted to recover revenue requirement	
314	UG Only Charge/1 light per 3 customers on wood pole 7,000/12,000 lumen	$0.79	-	$0.93	$0.93	17.7%	Rate adjusted to recover revenue requirement	
315	UG Only Charge/1 light per 10 customers on fiberglass/metal pole or post 7,000/12,000 lumen	$0.43	-	$0.51	$0.51	18.6%	Rate adjusted to recover revenue requirement	
316	UG Only Charge/1 light per 6 customers on fiberglass/metal/pole or post 7,000/12,000 lumen	$0.72	-	$0.85	$0.85	18.1%	Rate adjusted to recover revenue requirement	
317	UG Only Charge/1 light per 3 customers on fiberglass/metal/pole or post 7,000/12,000 lumen	$0.84	-	$0.99	$0.99	17.9%	Rate adjusted to recover revenue requirement	
318	UG Only Charge/1 light per 10 customers on wood pole 9,500 lumen	$0.48	-	$0.56	$0.56	16.7%	Rate adjusted to recover revenue requirement	
319	UG Only Charge/1 light per 5 customers on wood pole 9,500 lumen	$0.91	-	$1.07	$1.07	17.6%	Rate adjusted to recover revenue requirement	
320	UG Only Charge/1 light per 3 customers on wood pole 9,500 lumen	$1.07	-	$1.26	$1.26	17.8%	Rate adjusted to recover revenue requirement	
321	UG Only Charge/1 light per 10 customers on fiberglass/metal pole or post 9,500 lumen	$0.60	-	$0.71	$0.71	18.3%	Rate adjusted to recover revenue requirement	
322	UG Only Charge/1 light per 6 customers on fiberglass/metal/pole or post 9,500 lumen	$1.03	-	$1.21	$1.21	17.5%	Rate adjusted to recover revenue requirement	
323	UG Only Charge/1 light per 3 customers on fiberglass/metal/pole or post 9,500 lumen	$1.19	-	$1.40	$1.40	17.6%	Rate adjusted to recover revenue requirement	
324	UG Only Charge/1 light per 10 customers on wood pole LED 50	$0.52	-	$0.61	$0.61	17.3%	Rate adjusted to recover revenue requirement	
325	UG Only Charge/1 light per 5 customers on wood pole LED 50	$1.05	-	$1.23	$1.23	17.1%	Rate adjusted to recover revenue requirement	
326	UG Only Charge/1 light per 3 customers on wood pole LED 50	$1.76	-	$2.07	$2.07	17.6%	Rate adjusted to recover revenue requirement	
327	UG Only Charge/1 light per 10 customers on fiberglass/metal pole or post LED 50	$0.51	-	$0.60	$0.60	17.6%	Rate adjusted to recover revenue requirement	
328	UG Only Charge/1 light per 6 customers on fiberglass/metal/pole or post LED 50	$0.85	-	$1.00	$1.00	17.6%	Rate adjusted to recover revenue requirement	
329	UG Only Charge/1 light per 3 customers on fiberglass/metal/pole or post LED 50	$1.74	-	$2.04	$2.04	17.2%	Rate adjusted to recover revenue requirement	

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
330			Area Lighting Service Schedule ALS					kWh
331	9,500 Lumen SV	$10.75	-	$11.69	$12.49	8.7%	All fixture rates are adjusted by the same percentage to recover revenue requirement	46
332	16,000 Lumen SV	$12.87	-	$13.99	$15.02	8.7%	Rate adjusted to recover revenue requirement	59
333	28,500 Lumen SV	$16.97	-	$18.45	$20.36	8.7%	Rate adjusted to recover revenue requirement	109
334	50,000 Lumen SV	$21.30	-	$23.15	$25.81	8.7%	Rate adjusted to recover revenue requirement	152
335	50,000 Flood Lumen	$23.93	-	$26.01	$28.95	8.7%	Rate adjusted to recover revenue requirement	168
336	9,000 Lumen MH	$13.38	-	$14.54	$15.26	8.7%	Rate adjusted to recover revenue requirement	41
337	20,000 Lumen MH	$18.94	-	$20.59	$22.23	8.7%	Rate adjusted to recover revenue requirement	94
338	33,000 Lumen MH	$24.11	-	$26.21	$28.54	8.7%	Rate adjusted to recover revenue requirement	133
339	110,000 Lumen MH	$47.90	-	$52.07	$58.54	8.7%	Rate adjusted to recover revenue requirement	370
340	5,800 Lumen SV	$7.03	-	$7.64	$8.15	8.7%	Rate adjusted to recover revenue requirement	29
341	7,000 Lumen MV Semi-Enclosed	$8.06	-	$8.76	$9.97	8.7%	Rate adjusted to recover revenue requirement	69
342	7,000 Lumen MV	$9.59	-	$10.42	$11.63	8.7%	Rate adjusted to recover revenue requirement	69
343	12,000 Lumen RSV	$12.13	-	$13.19	$14.22	8.7%	Rate adjusted to recover revenue requirement	59
344	21,000 Lumen MV	$14.44	-	$15.70	$18.31	8.7%	Rate adjusted to recover revenue requirement	149
345	21,000 Lumen MV Flood	$17.95	-	$19.51	$22.31	8.7%	Rate adjusted to recover revenue requirement	160
346	22,000 Lumen SV	$13.68	-	$14.87	$16.37	8.7%	Rate adjusted to recover revenue requirement	86
347	38,000 Lumen RSV	$16.23	-	$17.64	$20.00	8.7%	Rate adjusted to recover revenue requirement	135
348	40,000 Lumen MH	$24.95	-	$27.12	$29.92	8.7%	Rate adjusted to recover revenue requirement	160
349	60,000 Lumen MV	$27.99	-	$30.43	$37.11	8.7%	Rate adjusted to recover revenue requirement	382
350	60,000 Lumen MV Flood	$30.47	-	$33.12	$39.80	8.7%	Rate adjusted to recover revenue requirement	382
351	LED 50	$9.62	-	$10.46	$10.77	8.7%	Rate adjusted to recover revenue requirement	18
352	LED 50 Flood	$10.95	-	$11.90	$12.21	8.7%	Rate adjusted to recover revenue requirement	18
353	LED 75	$9.89	-	$10.75	$11.19	8.7%	Rate adjusted to recover revenue requirement	25
354	LED 105	$11.51	-	$12.51	$13.12	8.7%	Rate adjusted to recover revenue requirement	35
355	LED 130 Flood	$20.29	-	$22.06	$22.83	8.7%	Rate adjusted to recover revenue requirement	44
356	LED 150	$15.09	-	$16.40	$17.34	8.7%	Rate adjusted to recover revenue requirement	54
357	LED 215	$18.75	-	$20.38	$21.66	8.7%	Rate adjusted to recover revenue requirement	73
358	LED 260 Flood	$35.71	-	$38.82	$40.36	8.7%	Rate adjusted to recover revenue requirement	68
359	LED 280	$22.18	-	$24.11	$25.88	8.7%	Rate adjusted to recover revenue requirement	101
360	LED 420	$54.89	-	$59.67	$62.15	8.7%	Rate adjusted to recover revenue requirement	142
361	LED 530	$66.67	-	$72.47	$75.60	8.7%	Rate adjusted to recover revenue requirement	179
362	LED 75 (Standard Offer)	$7.60	-	$8.26	$8.70	8.7%	Rate adjusted to recover revenue requirement	25
363	LED 105 (Standard Offer)	$10.83	-	$11.77	$12.38	8.7%	Rate adjusted to recover revenue requirement	35
364	LED 215 (Standard Offer)	$16.23	-	$17.64	$18.92	8.7%	Rate adjusted to recover revenue requirement	73
365	LED 205 Site Lighter (Standard Offer)	$16.23	-	$17.64	$18.85	8.7%	Rate adjusted to recover revenue requirement	69
366	Monthly UG Charge	$3.90	-	$4.24	$4.24	8.7%	Rate adjusted to recover revenue requirement by the same percentage as fixture rates	
367	One-Time UG Charge	$518.00	-	$600.00	$600.00	15.8%	Rate adjusted to match approximate underground trenching work order costs	
368	Wood Pole	$2.42	-	$2.84	$2.84	17.4%	Increased based upon updated cost study	
369	Metal, Fiberglass or Post Pole	$5.60	-	$6.57	$6.57	17.3%	Increased based upon updated cost study	
370	12-Foot Smooth Concrete Post	$12.03	-	$14.74	$14.74	22.5%	Increased based upon updated cost study	
371	16-Foot Smooth Concrete Post	$13.24	-	$16.22	$16.22	22.5%	Increased based upon updated cost study	
372	Decorative Square Metal	$14.10	-	$16.55	$16.55	17.4%	Increased based upon updated cost study	
373	13-Foot Fluted Concrete Post	$18.05	-	$22.11	$22.11	22.5%	Increased based upon updated cost study	
374	Decorative Aluminum 12-Foot Post	$21.66	-	$26.53	$26.53	22.5%	Increased based upon updated cost study	
375	Decorative 35- or 39-Foot Tapered Metal Pole	$34.40	-	$42.14	$42.14	22.5%	Increased based upon updated cost study	
376	Masterpiece Series A 12-Foot Decorative Post	$21.66	-	$26.53	$26.53	22.5%	Increased based upon updated cost study	
377	Masterpiece Series A 16-Foot Decorative Post	$26.47	-	$32.43	$32.43	22.5%	Increased based upon updated cost study	
378	Masterpiece Series A Twin Mounting Bracket	$5.00	-	$5.00	$5.00	0.0%	No change proposed	
379	Masterpiece Series A Adder	$3.00	-	$3.25	$3.25	8.3%	Increased based upon updated cost study	
380	Masterpiece Series B Adder	$4.15	-	$4.50	$4.50	8.4%	Increased based upon updated cost study	

Attachment C

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
381	**Residential Service Energy Conservation Rider RECD**							
382	All Charges						Proposed 5% discount on base rates, excluding riders	
383	**Intermittent and Highly Fluctuating Load Rider No. 9**							
384	HFIL KVA	$0.40	-	$0.40	$0.40	0.0%	No change proposed	
385	**Large Load Curtailable Rider 7**							
386	Contract - Billed kW (Block 1)	$1.25		$1.29	$1.29	3.2%	Rate Adjusted to match percentage increase to the LGS-CUR-TOU schedule	
387	Contract - Billed kW (Block 2)	$1.00		$1.03	$1.03	3.0%	Rate Adjusted to match percentage increase to the LGS-CUR-TOU schedule	
388	Contract - Billed kW (Block 3)	$1.50		$1.55	$1.55	3.3%	Rate Adjusted to match percentage increase to the LGS-CUR-TOU schedule	
389	Excess Standby Usage Charge	$0.40		$0.41	$0.41	2.5%	Rate Adjusted to match percentage increase to the LGS-CUR-TOU schedule	
390	**Large Load Curtailable Rider LLC**							
391	Customer Charge	$50.00	-	$55.00	$55.00	10.0%	Rate adjusted based on updated cost study	
392	Average On-peak - Firm kW	($4.60)	-	($4.90)	($4.90)	6.5%	Rate adjusted based on updated cost study	
393	Billing kW - Firm kW	$1.62	-	$1.46	$1.46	-9.9%	Matches last fuel filing	
394	Level 1 Capacity Charge	$2.30	-	$2.40	$2.40	4.3%	Rate adjusted based on updated cost study	
395	Failure Charge Rate	$45.00	-	$40.00	$40.00	-11.1%	No change proposed	
396	Variable Environmental Charge (Fuel Adjustment)	$0.89	-	$0.89	$0.89	0.0%	No change proposed	
397	**Dispatched Power Service Rider No. 68**							
398	Customer Charge	$50.00	-	$55.00	$55.00	10.0%	Rate adjusted based on updated cost study	
399	Incremental On-peak kWh	$0.01500	-	$0.01500	$0.01500	0.0%	No change proposed for Non LGS-TOU schedules	
400	Incremental On-peak kWh (NEW TOU)	$0.00000		$0.01500	$0.01500	-	Split out rates for new LGS-TOU periods	
401	Incremental Off-peak kWh (NEW TOU)	$0.00000		$0.00698	$0.00698	-	Split out rates for new LGS-TOU periods	
402	**Incremental Power Service Rider IPS**							
403	Customer Charge	$50.00	-	$55.00	$55.00	10.0%	Rate adjusted based on updated cost study	
404	Incremental On-peak kWh	$0.01500	-	$0.00000	$0.00000	-	Split out rates for new LGS-TOU periods	
405	Incremental On-peak kWh (NEW TOU)	$0.00000	-	$0.01500	$0.01500	-	Split out rates for new LGS-TOU periods	
406	Incremental Off-peak kWh (NEW TOU)	$0.00000	-	$0.00698	$0.00698	-	Split out rates for new LGS-TOU periods	
407	**Economic Development Rider ED**							
408	Year 1 to 5 Discount Rates						No change proposed	
409	**Economic Redevelopment Rider ERD**							
410	ERD Discount Amount						No changed proposed	
411	**Supplementary and Non-Firm Standby Service Rider NFS**							
412	NFS Customer Charge	$50.00	-	$55.00	$55.00	10.0%	Rate adjusted based on updated cost study	
413	Standby Delivery Charge (Transmission)	$0.00261	-	$0.00590	$0.00590	126.1%	No changed proposed	
414	Standby Delivery Charge (Distribution)	$0.00507	-	$0.01180	$0.01180	132.7%	No changed proposed	
415	Tax Factor	0.52%	-	0.52%	0.52%	0.0%	No change proposed; Rate reflects 0.3% gross receipts tax and current 0.2202638088% SC Regulatory Fee	
416	**Supplementary and Firm Standby Service Rider SS**							
417	Generation Reservation Charge	$0.84	-	$0.81	$0.81	-3.6%	Rate adjusted based on updated cost study	
418	Tax Factor	0.52%	-	0.52%	0.52%	0.0%	No change proposed; Rate reflects 0.3% gross receipts tax and current 0.2202638088% SC Regulatory Fee	
419	**Rider SS - Only Applicable for Capacity Factor of 80% or greater**							
420	SS Delivery Charge (Transmission)	$1.30	-	$2.98	$2.98	129.2%	Rate adjusted based on updated cost study	
421	SS Delivery Charge (Distribution)	$2.54	-	$5.79	$5.79	128.0%	Rate adjusted based on updated cost study	
422	**Meter-Related Optional Programs Rider MROP**							
423	Total Meter	$3.00	-	$0.00	$0.00	-100.0%	Program no longer available	
424	Total Meter - Wireless	$13.20	-	$0.00	$0.00	-100.0%	Program no longer available	
425	Total Meter Termination Charge	$50.00	-	$0.00	$0.00	-100.0%	Program no longer available	
426	EPO - Totalized Monthly	$20.00	-	$0.00	$0.00	-100.0%	Rate adjusted based on updated cost study	
427	EPO - Daily	$20.00	-	$15.00	$15.00	-25.0%	Rate adjusted based on updated cost study	
428	EPO Set-Up Charge	$85.00	-	$0.00	$0.00	-100.0%	Program no longer available	
429	EPO Set-Up Charge - Totalized	$85.00	-	$0.00	$0.00	-100.0%	Program no longer available	
430	MRM - Initial Set-up Fee	$170.00	-	$170.00	$170.00	0.0%	No change proposed	
431	MRM - Monthly Rate	$14.75	-	$16.50	$16.50	11.9%	No change proposed	
432	MRM- Early Termination Charge	$50.00	-	$50.00	$50.00	0.0%	No change proposed	
433	Non-Standard Meter Monthly Rate	$0.33	-	$0.79	$0.79	139.4%	Rate adjusted based on updated cost study	
434	Non-Standard Meter Set-Up	$15.00	-	$30.00	$30.00	100.0%	Rate adjusted based on updated cost study	
435	Non-Standard Meter Exchange	$77.00	-	$100.00	$100.00	29.9%	Rate adjusted based on updated cost study	

Attachment C

Reed Settlement Exhibit No. 3
9 of 9

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Twelve Months Ended December 31, 2021
Reed Settlement Exhibit No. 3 - Derivation and Description of Rate and Tariff Changes

	Description	Current Rate with Embedded Riders (9/1/2022)	New TOU Current Equivalent with Embedded Riders** (9/1/2022)	Proposed Rate with Embedded Riders	Proposed Rate without Embedded Riders	Percentage Change	Rationale for Change	Lighting kWh
436	Service Regulations							
437	SC Service Charge Revenue	$17.00	-	$8.00	$8.00	-52.9%	Rate adjusted based on updated cost study	
438	SC Service Charge - Landlord Revenue	$5.35	-	$1.00	$1.00	-81.3%	Rate adjusted based on updated cost study	
439	SC Reconnect Charge Revenue	$19.00	-	$8.00	$8.00	-57.9%	Rate adjusted based on updated cost study	
440	SC After Hours Reconnect Charge Revenue	$19.00	-	$8.00	$8.00	-57.9%	Rate adjusted based on updated cost study	
441	SC Return Check Fee	$20.00	-	$5.00	$5.00	-75.0%	Rate adjusted based on updated cost study	
442	SC Additional Facilities Charges (Non-Contributory)	1.0%	-	1.0%	1.0%	0.0%	No change proposed	
443	SC Additional Facilities Charges (Contributory)	0.3%	-	0.3%	0.3%	0.0%	No change proposed	
444	Billed kVAR	$0.30	-	$0.30	$0.30	0.0%	No change proposed	
445								
446	Residential Service Time of Use with Critical Peak Schedule R-TOU-CPP (New Tariff)							
447	Basic Facilities Charge	-	-	$14.63	$14.63	0.0%	Rate Proposed for New R-TOU-CPP Tariff	
448	Energy Charges Critical Peak kWh	-	-	$0.35000	$0.34748	0.0%	Rate Proposed for New R-TOU-CPP Tariff	
449	Energy Charges On-Peak kWh	-	-	$0.30760	$0.30508	0.0%	Rate Proposed for New R-TOU-CPP Tariff	
450	Energy Charges Off-Peak kWh	-	-	$0.12550	$0.12298	0.0%	Rate Proposed for New R-TOU-CPP Tariff	
451	Energy Charges Discount kWh	-	-	$0.08670	$0.08418	0.0%	Rate Proposed for New R-TOU-CPP Tariff	
452	Three Phase Charge	-	-	$9.00	9	0.0%	Rate Proposed for New R-TOU-CPP Tariff	

** Represents non-approved rates for the new TOU Periods that provide equivalent revenue to the approved rates based on 2021 billing determinants

Attachment D

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Reed Settlement Exhibit No. 5

Comparison of Annual Average Present and Proposed Rates by Major Schedule

(Includes Annual DSM/EE Rider, EDIT-1 Rider, but excludes Fixed Monthly Rider 39 Charge which is billed at the account level)

Line No.	Residential Service Schedule RES				
1	kWh	Present Revenue*	New TOU Present Revenue Equivalent**	Proposed Revenue	Percent Increase
2	0	$11.78	$11.78	$11.78	0.0%
3	100	$23.94	$23.90	$25.03	4.6%
4	250	$42.17	$42.07	$44.91	6.5%
5	500	$72.56	$72.36	$78.04	7.5%
6	750	$102.95	$102.64	$111.16	8.0%
7	1,000	$132.01	$131.60	$142.96	8.3%
8	2,000	$246.90	$246.08	$268.80	8.9%
9	3,000	$361.79	$360.56	$394.64	9.1%
10	4,000	$476.69	$475.05	$520.49	9.2%
11	5,000	$591.58	$589.53	$646.33	9.3%
12	6,000	$706.47	$704.01	$772.17	9.3%
13					

Line No.	Residential Service Time of Use R-TOUD					
14						
15	Total kWh	On-peak kW***	Present Revenue*	New TOU Present Revenue Equivalent**	Proposed Revenue	Percent Increase
16	0	0	$14.63	$14.63	$14.63	0.0%
17	100	1	$25.41	$24.89	$26.49	4.2%
18	250	1	$40.19	$38.85	$42.63	6.1%
19	500	2	$62.94	$60.22	$67.33	7.0%
20	750	2	$85.91	$81.59	$92.03	7.1%
21	1,000	3	$110.44	$105.81	$120.04	8.7%
22	2,000	5	$201.45	$191.30	$218.84	8.6%
23	3,000	8	$297.26	$282.48	$324.25	9.1%
24	4,000	11	$393.06	$373.66	$429.65	9.3%
25	5,000	13	$484.08	$459.14	$528.46	9.2%
26	6,000	16	$579.89	$550.33	$633.86	9.3%

Line No.	Small General Service Schedule SGS			
27				
28				
29	kWh	Present Revenue	Proposed Revenue	Percent Increase
30	0	$12.34	$14.00	13.5%
31	100	$26.50	$28.71	8.4%
32	250	$47.73	$50.79	6.4%
33	500	$83.12	$87.57	5.4%
34	750	$118.50	$124.36	4.9%
35	1,000	$153.89	$161.14	4.7%
36	2,000	$295.44	$308.28	4.3%
37	3,000	$400.40	$417.39	4.2%
38	4,000	$505.36	$526.49	4.2%
39	5,000	$610.32	$635.60	4.1%
40	6,000	$715.28	$744.70	4.1%

Attachment D

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Reed Settlement Exhibit No. 5

Comparison of Annual Average Present and Proposed Rates by Major Schedule

(Includes Annual DSM/EE Rider, EDIT-1 Rider, but excludes Fixed Monthly Rider 39 Charge which is billed at the account level)

41	Medium General Service Schedule MGS				
42					
43	kWh	Billing kW	Present Revenue	Proposed Revenue	Percent Increase
44	0	0	$193.85	$203.75	5.1%
45	6,000	30	$749.27	$781.44	4.3%
46	10,000	35	$1,131.05	$1,178.55	4.2%
47	30,000	75	$3,143.45	$3,271.95	4.1%
48	50,000	125	$5,224.85	$5,437.25	4.1%
49	75,000	175	$7,740.35	$8,054.00	4.1%
50	100,000	250	$10,428.35	$10,850.50	4.0%
51	150,000	375	$15,631.85	$16,263.75	4.0%
52	200,000	500	$20,835.35	$21,677.00	4.0%
53	300,000	750	$31,242.35	$32,503.50	4.0%
54	400,000	900	$40,959.35	$42,611.00	4.0%
55	500,000	999	$50,324.45	$52,351.81	4.0%

56	Small Service Time of Use SGS-TOU (Proposed MGS-TOU)					
57						
58	Total kWh	On-peak kW***	Present Revenue*	New TOU Present Revenue Equivalent**	Proposed Revenue	Percent Increase
59	0	0	$27.85	$27.85	$33.00	18.5%
60	100	1	$40.44	$40.65	$46.38	14.7%
61	250	1	$56.48	$56.65	$63.04	11.6%
62	500	2	$79.39	$79.06	$86.27	8.7%
63	750	2	$102.49	$101.46	$109.50	6.8%
64	1,000	3	$130.22	$130.27	$139.54	7.2%
65	2,000	5	$221.87	$219.89	$232.45	4.8%
66	5,000	13	$518.27	$514.34	$538.44	3.9%
67	10,000	25	$997.97	$988.04	$1,030.26	3.2%
68	30,000	75	$2,938.20	$2,908.43	$3,024.78	2.9%
69	50,000	125	$4,878.43	$4,828.82	$5,019.30	2.9%
70	75,000	175	$7,169.77	$7,069.36	$7,342.15	2.4%
71	100,000	250	$9,729.02	$9,629.79	$10,005.60	2.8%
72	150,000	375	$14,579.60	$14,430.76	$14,991.90	2.8%
73	200,000	500	$19,430.18	$19,231.74	$19,978.20	2.8%
74	300,000	750	$29,131.35	$28,833.68	$29,950.79	2.8%
75	400,000	900	$37,760.85	$37,156.08	$38,561.02	2.1%
76	500,000	999	$45,843.80	$44,825.91	$46,476.44	1.4%

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Reed Settlement Exhibit No. 5

Comparison of Annual Average Present and Proposed Rates by Major Schedule

(Includes Annual DSM/EE Rider, EDIT-1 Rider, but excludes Fixed Monthly Rider 39 Charge which is billed at the account level)

77 **Large General Service Schedule LGS**

78

79	kWh	Billing kW	Present Revenue	Proposed Revenue	Percent Increase
80	0	0	$14,112	$14,420	2.2%
81	300,000	1,000	$33,942	$34,667	2.1%
82	400,000	1,000	$40,552	$41,416	2.1%
83	600,000	1,000	$53,772	$54,914	2.1%
84	750,000	2,500	$84,567	$86,368	2.1%
85	1,100,000	2,500	$107,702	$109,989	2.1%
86	1,500,000	2,500	$134,142	$136,985	2.1%
87	1,500,000	5,000	$168,942	$172,535	2.1%
88	2,200,000	5,000	$215,212	$219,778	2.1%
89	2,900,000	5,000	$261,482	$267,021	2.1%
90	2,200,000	7,500	$247,512	$252,828	2.1%
91	3,300,000	7,500	$320,222	$327,067	2.1%
92	4,400,000	7,500	$392,932	$401,306	2.1%
93	2,900,000	10,000	$326,082	$333,121	2.2%
94	4,300,000	10,000	$418,622	$427,607	2.1%
95	5,800,000	10,000	$517,772	$528,842	2.1%
96	5,800,000	20,000	$636,972	$651,042	2.2%
97	8,700,000	20,000	$828,662	$846,763	2.2%
98	11,600,000	20,000	$1,020,352	$1,042,484	2.2%
99	14,600,000	50,000	$1,576,252	$1,611,554	2.2%
100	21,900,000	50,000	$2,058,782	$2,104,231	2.2%
101	29,200,000	50,000	$2,541,312	$2,596,908	2.2%

102 **Large Service Time of Use LGS-TOU**

103

104	Total kWh	On-peak kW***	Present Revenue*	New TOU Present Revenue Equivalent**	Proposed Revenue	Percent Increase
105	0	0	$1,502	$1,324	$1,410	-6.1%
106	450,000	1,000	$45,321	$46,757	$48,407	6.8%
107	575,000	1,000	$52,838	$53,774	$55,474	5.0%
108	660,000	1,000	$57,860	$58,545	$60,280	4.2%
109	1,100,000	2,500	$111,483	$115,202	$119,304	7.0%
110	1,460,000	2,500	$133,179	$135,409	$139,658	4.9%
111	1,640,000	2,500	$143,755	$145,513	$149,835	4.2%
112	2,190,000	5,000	$222,162	$229,651	$237,844	7.1%
113	2,920,000	5,000	$266,166	$270,627	$279,116	4.9%
114	3,285,000	5,000	$287,621	$291,114	$299,752	4.2%
115	4,380,000	10,000	$439,132	$456,488	$472,680	7.6%
116	5,840,000	10,000	$527,141	$538,438	$555,225	5.3%
117	6,570,000	10,000	$570,050	$579,413	$596,497	4.6%
118	8,760,000	20,000	$863,071	$904,127	$935,897	8.4%
119	11,680,000	20,000	$1,039,089	$1,068,027	$1,100,985	6.0%
120	13,140,000	20,000	$1,124,908	$1,149,978	$1,183,530	5.2%
121	21,900,000	50,000	$2,134,891	$2,244,681	$2,323,017	8.8%
122	29,200,000	50,000	$2,574,935	$2,654,432	$2,735,739	6.2%
123	32,850,000	50,000	$2,789,482	$2,859,307	$2,942,099	5.5%

*** Represents approved rates with the current TOU Periods**

**** Represents non-approved rates for the new TOU Periods that provide equivalent revenue to the approved rates based on 2021 billing determinants**
***** Represents Billing Determinants used in the old TOU periods.**

Attachment E

Duke Energy Progress, LLC
PSCSC Docket No. 2022-254-E
Reed Settlement Exhibit No. 7 - Derivation of the EDIT-1 Rider

	(A) Rate Class	(B)	(C) Approved EDIT-1 Rate 6/1/2022	(D) Adjusted Test Year kWh Sales	(E) Update to EDIT-1 Rider	(F) Proposed Change in EDIT-1 Rate 4/1/2023	(G) Proposed EDIT-1 Rate 4/1/2023
1	Residential	per kWh	($0.00154)	2,077,782,711	($8,790,883)	($0.00423)	($0.00577)
2	General Service (Small)	per kWh	($0.00176)	249,818,818	($1,089,832)	($0.00436)	($0.00612)
3	General Service (Constant Load)	per kWh	($0.00159)	5,783,201	($22,455)	($0.00388)	($0.00547)
4	General Service (Medium)	per kWh	($0.00090)	1,539,475,264	($3,257,655)	($0.00212)	($0.00302)
5	General Service (Large)	per kWh	($0.00050)	2,076,468,161	($2,273,188)	($0.00109)	($0.00159)
5	Traffic Signal Service	per kWh	($0.00298)	1,926,224	($12,016)	($0.00624)	($0.00922)
6	Outdoor Lighting	per kWh	($0.00471)	72,638,710	($928,158)	($0.01278)	($0.01749)
7	Sports Field Lighting	per kWh	($0.00298)	139,620	($1,609)	($0.01152)	($0.01450)
8	Seasonal	per kWh	($0.00120)	13,354,534	($50,022)	($0.00375)	($0.00495)
9	Total			6,037,387,243	($16,425,818)		